DOE/EIA-M063(2010)

Documentation of the Oil and Gas Supply Module (OGSM)

May 2010

Office of Integrated Analysis and Forecasting
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2010*. The major changes include:

- Restructuring of the documentation so that each major submodule is described in separate chapters

- Description of the new Onshore Lower 48 Oil and Gas Supply Submodule--this submodule replaces the previous methodology used to generate conventional and unconventional lower 48 onshore oil and gas supply projections

- Updates to the assumptions used for the announced/nonproducing offshore discoveries

- Inclusion of carbon dioxide emissions costs in the oil shale project economics evaluation.

Contents

Tables

Figures

1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Module (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the U.S. Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2)).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within National Energy Modeling System (NEMS) by the OGSM. OGSM encompasses both conventional and unconventional domestic crude oil and natural gas supply. Crude oil and natural gas projections are further disaggregated by geographic region. OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

OGSM also represents foreign natural gas trade via pipeline from Canada. Liquefied natural gas (LNG) trade and natural gas trade with Mexico are determined in the Natural Gas Transmission and Distribution Module (NGTDM). These import supply functions are critical elements of any market modeling effort.

OGSM utilizes both exogenous input data and data from other modules within NEMS. The primary exogenous inputs are resource levels, finding rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the NGTDM. From the Petroleum Market Model (PMM) come projections of the crude oil wellhead prices at the OGSM regional level. Important economic factors, namely interest rates and GDP deflators flow to OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the integrating, or system module.

Outputs from OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of NEMS. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (the parameters for which are provided by OGSM) to determine nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by NGTDM and the oil volumes are used by PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. OGSM also provides projections of natural gas production to PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided to the Macroeconomic Module to assist in forecasting aggregate measures of output.

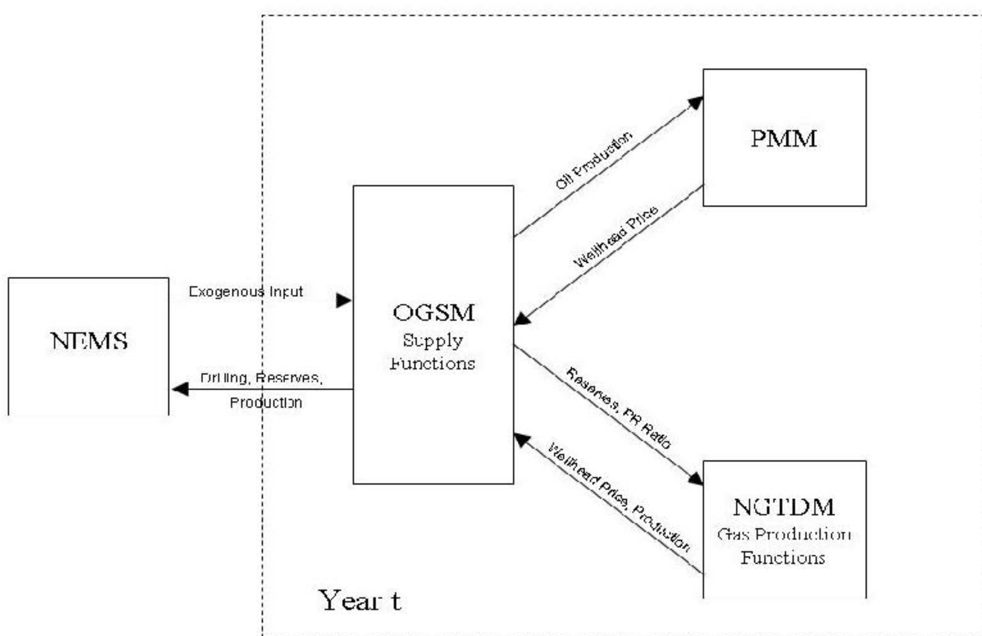
OGSM is archived as part of the National Energy Modeling System (NEMS). The archival package of NEMS is located under the model acronym NEMS2010. The NEMS version documented is that used to produce the *Annual Energy Outlook 2010 (AEO2010)*. The package is available through the National Technical Information Service.

Model Purpose

OGSM is a comprehensive framework with which to analyze oil and gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production, and natural gas imports and exports in response to price data received endogenously (within NEMS) from the Natural Gas Transmission and Distribution Model (NGTDM) and the Petroleum Market Model (PMM). Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides to the NGTDM beginning-of-year reserves and production-to-reserves ratio for use in the short-term domestic nonassociated gas production functions that reside in the NGTDM and associated-dissolved natural gas production. The interaction of supply and demand in NGTDM determines nonassociated gas production.

Figure 1-1. OGSM Interface with Other Oil and Gas Modules



The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 1-2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by nonassociated and associated-dissolved gas.[1] Nonassociated natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

OGSM provides mid-term (through year 2035) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables including:

- drilling costs, production costs,
- regulatory or legislatively mandated environmental costs,
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits, and
- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables OGSM to address some financial issues. In particular, the treatment of financial resources within OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

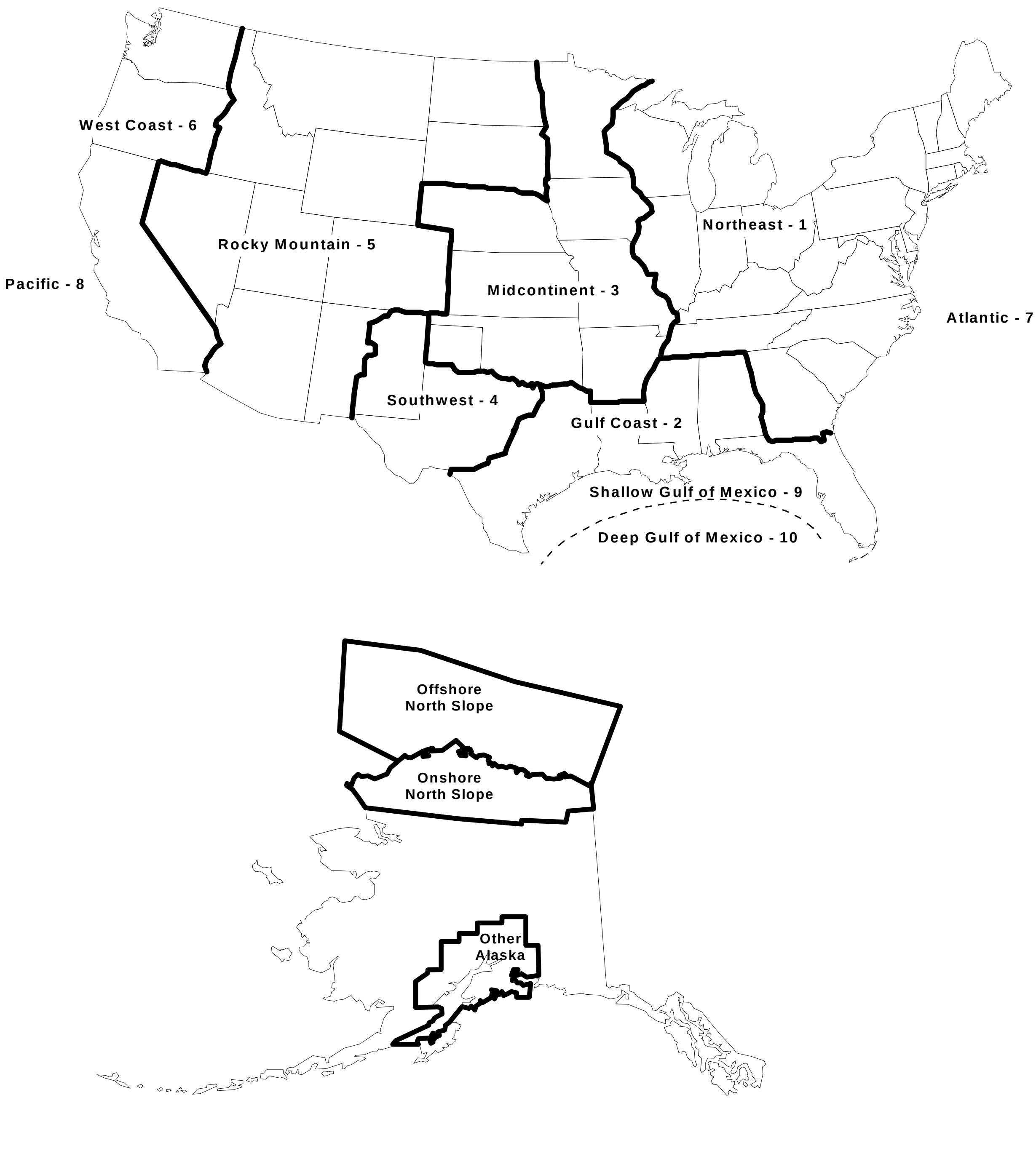
- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and

[1]Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

In general, OGSM is used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 1-2. Oil and Gas Supply Regions

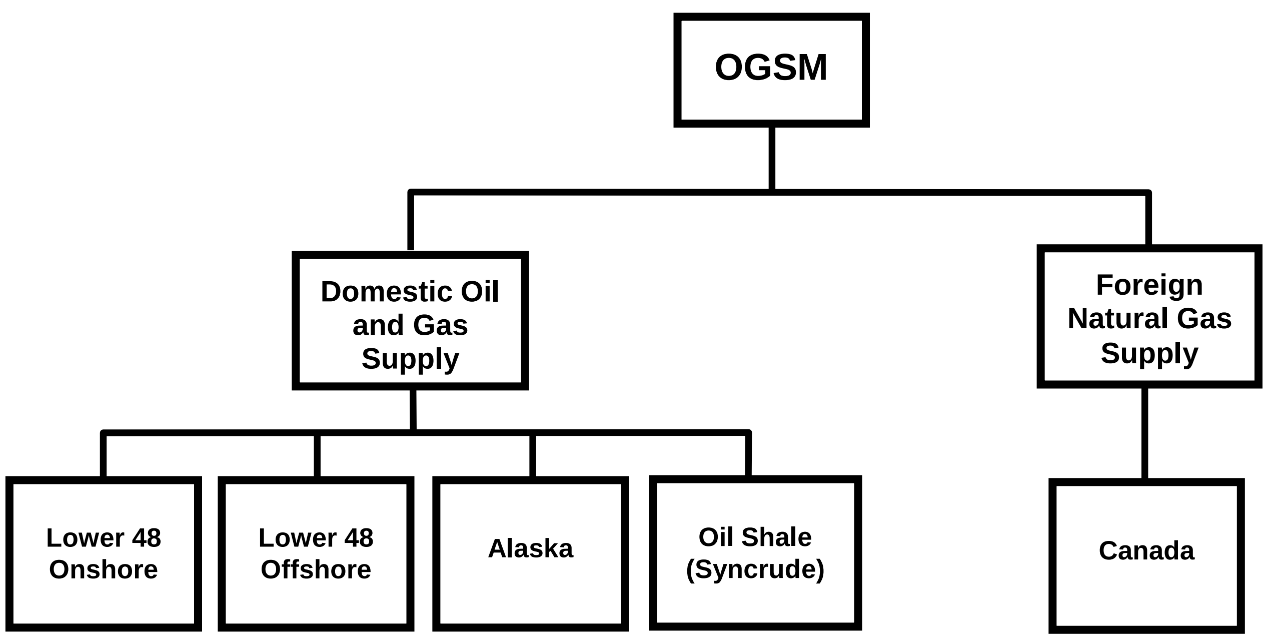


Model Structure

The Oil and Gas Supply Module (OGSM) of the National Energy Modeling System (NEMS), which consists of a set of submodules (Figure 1-3) is used to perform supply analysis of domestic oil and gas production and foreign trade in natural gas between the United States and Canada via pipeline. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States, or acquire natural gas from Canadian producers for resale in the United States, or sell U.S. gas to foreign consumers. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents Canadian trade in natural gas as pipeline imports and exports by entry region of the United States. Liquefied natural gas (LNG) imports and Mexico natural gas imports/exports are determined in the NGTDM.

Figure 1-3. Submodules within the Oil and Gas Supply Module



The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM, compared to the previous EIA midterm model, incorporates a more complete and representative description of the processes by which oil and gas in the technically recoverable resource base[2] convert to proved reserves.[3]

The breadth of supply processes that are encompassed within OGSM results in different methodological approaches for determining crude oil and natural gas production from lower 48 onshore, lower 48 offshore, Alaska, and Canada. The present OGSM consequently comprises five submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the lower 48. The Offshore Oil and Gas Supply Submodule (OOGSS) represents oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) represents industry supply activity in Alaska. Oil shale (synthetic) is model in the Oil Shale Supply Submodule (OSSS). The Foreign Natural Gas Supply Submodule (FNGSS) models trade in natural gas between the United States and Canada. These distinctions are reflected in the presentation of the methodology in the following chapters. A set of four appendices are included following the chapters that provide a description of the discounted cash flow (DCF) calculation, bibliography, model abstract, and an inventory of key output variables.

[2] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[3] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

U.S. onshore lower 48 crude oil and natural gas supply is determined by the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects which are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels.

OLOGSS utilizes both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data includes technical production for each project considered, cost and development constraint data, tax information, and project development data. Regional projections of natural wellhead prices and production are provided by the Natural Gas Transmission and Distribution Model (NGTDM). From the Petroleum Market Module (PMM) come projections of the crude oil wellhead prices at the OGSM regional level.

Model Purpose

OLOGSS is a comprehensive model with which to analyze the crude oil and natural gas supply potential and related economic issues. Its primary purpose is to produce projections of crude oil and natural gas from the onshore lower 48 in response to price data received from the PMM and the NGTDM. As a supply submodule, OLOGSS does not project prices.

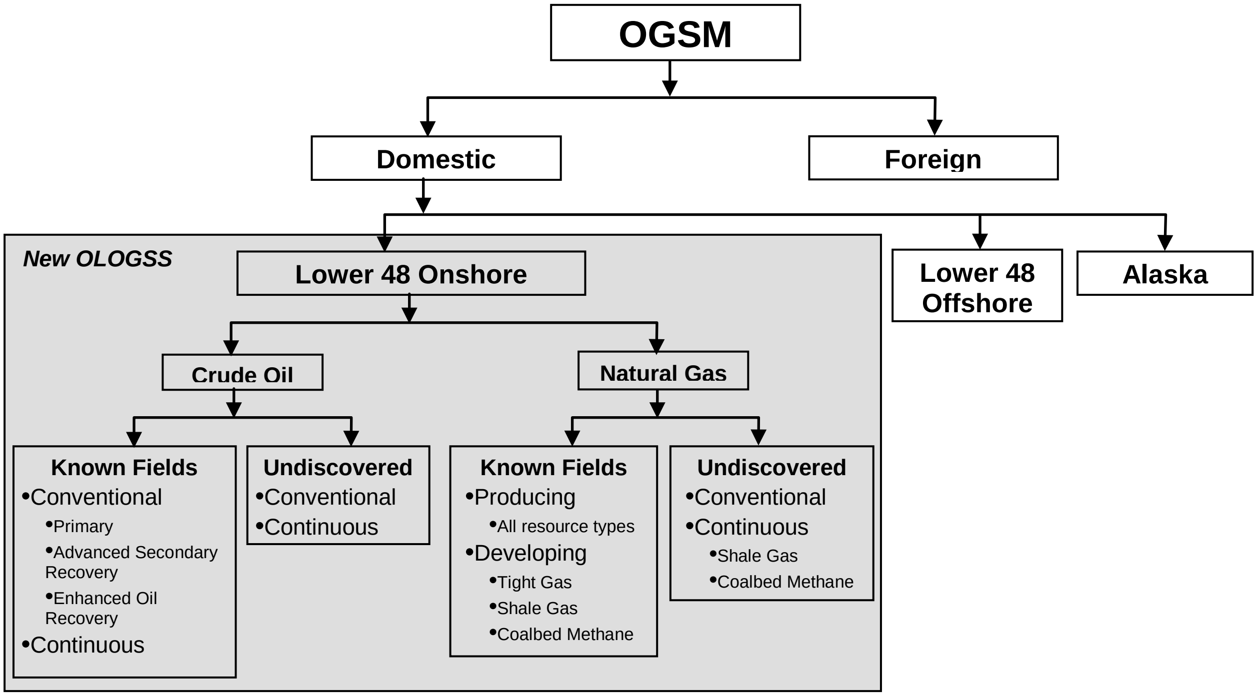
The basic interaction between OLOGSS and the OGSM is illustrated in figure 2-1. As seen in the figure, OLOGSS models the entirety of the domestic crude oil and natural gas within the onshore lower 48.

Resources Modeled

Crude Oil Resources

Crude oil resources, as illustrated in figure 2-1, are divided into known fields and undiscovered fields. For known resources, exogenous production type curves are used for quantifying the technical production profiles from known fields under primary, secondary, and tertiary recovery processes. Primary resources are also quantified for their advanced secondary recovery (ASR) processes that include: waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing enhanced oil recovery (EOR) processes such as: CO_2 flooding, steam flooding, polymer flooding and profile modification. Known crude oil resources include highly fractured continuous zones such as the Austin chalk formations and the Bakken shale formations.

Figure 2-1: Subcomponents within OGSM



Undiscovered crude oil resources are characterized in a method similar to that used for discovered resources and are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on United States Geological Survey (USGS) estimates and is distinguished as conventional and continuous. Conventional crude oil and natural gas resources are defined as discrete fields with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional resources commonly have relatively high permeability and obvious seals and traps. In contrast, continuous resources commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous resources have very low permeability, do not have obvious seals and traps, are in close proximity to source rocks, and are abnormally pressured. Included in the category of continuous accumulations are hydrocarbons that occur in tight reservoirs, shale reservoirs, fractured reservoirs, and coal beds.

Natural Gas Resources

Natural gas resources, as illustrated in figure 2-1, are divided into known producing fields, developing natural gas plays, and undiscovered fields. Exogenous production type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based upon resource estimates developed by the USGS. Existing databases of developing plays, such as the Marcellus Shale, have been incorporated into the model's resource base. The natural gas resource estimates have been developed from detailed geological characterizations of producing plays.

Processes Modeled

OLOGSS models primary, secondary and tertiary oil recovery processes. For natural gas, OLOGSS models discovered and undiscovered fields, as well as discovered and developing fields. Table 2-1 lists the processes modeled by OLOGSS.

Table 2-1: Processes Modeled by OLOGSS

Crude Oil Processes	Natural Gas Processes
Existing Fields and Reservoirs	Existing Radial Flow
Waterflooding in Undiscovered Resources	Existing Water Drive
CO_2 Flooding	Existing Tight Sands
Steam Flooding	Existing Dry Coal/Shale
Polymer Flooding	Existing Wet Coal/Shale
Infill Drilling	Undiscovered Conventional
Profile Modification	Undiscovered Tight Gas
Horizontal Continuity	Undiscovered Coalbed Methane
Horizontal Profile	Undiscovered Shale Gas
Undiscovered Conventional	Developing Shale Gas
Undiscovered Continuous	Developing Coalbed Methane
	Developing Tight Gas

Major Enhancements

OLOGSS is a play-level model, which projects the crude oil and natural gas supply from the onshore lower 48. The modeling procedure includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision. Technology advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The model is able to evaluate the impact of research and development (R&D) on supply and reserves. Furthermore, the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner.

OLOGSS possesses the capability to address issues which affect the profitability of development through a variety of levers, modeled as:

- Development of new technologies
- Rate of market penetration of new technologies
- Costs to implement new technologies
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

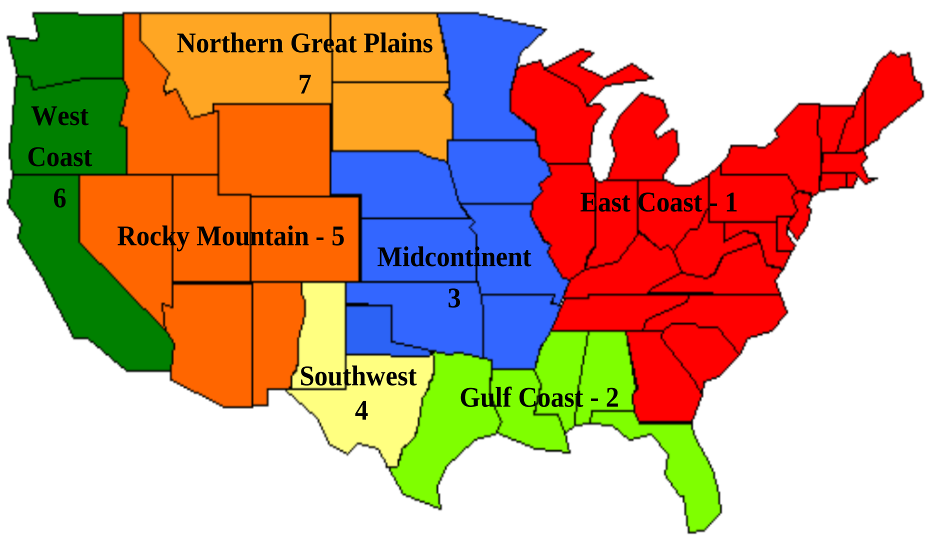
In addition, OLOGSS has the capability to address resource base issues. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (i.e., geographic region/fuel type combinations).

OLOGSS is capable of addressing access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible due to development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

OLOGSS uses the same geographical regions as the OGSM with one distinction. In order to capture the regional differences in costs and drilling activities in the Rocky Mountain region, the region has been divided into two sub-regions. These regions along with the original six are illustrated in figure 2-2. The Rocky Mountain region has been split to add the Northern Great Plains region. The results of these regions are aggregated before being passed to other OGSM or NEMS routines.

Figure 2-2: Seven OLOGSS Regions for Onshore Lower 48



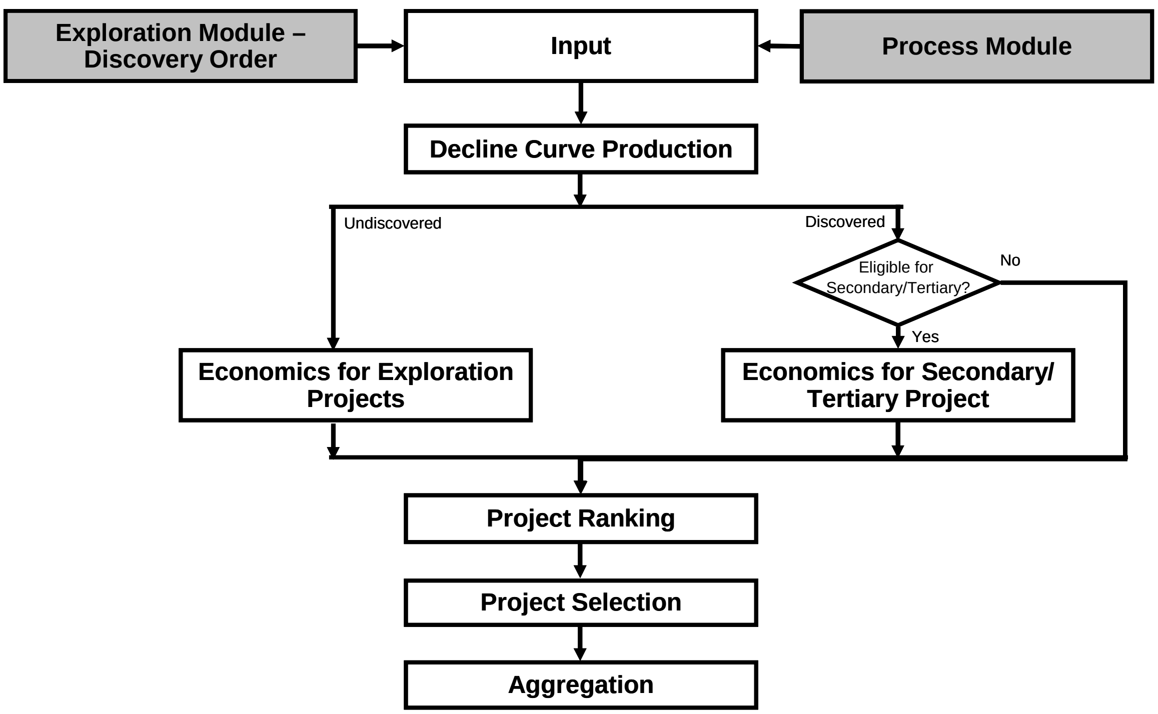
Model Structure

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and the competition for capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

Overall System Logic

Figure 2-3 provides the overall system logic for the OLOGSS timing and economic module. This is the only component of OLOGSS which is integrated into NEMS.

Figure 2-3: OLOGSS Timing Module Overall System Logic



As seen in the figure, there are two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects which may be discovered in the next thirty years. It also determines the discovery order in which the projects will be evaluated by OLOGSS. The process module calculates the well-level technical production from known crude oil and natural gas fields, EOR and advanced secondary recovery (ASR) projects, and developing natural gas plays.

OLOGSS determines the potential domestic production in three phases. As seen in Figure 2-3, the first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or EOR/ASR. Each year, the exploration projects are subject to economic analysis which determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The projects which are eligible are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if there are sufficient development resources available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of CO_2 floods through an increase in total pore volume injected.

The production, reserves, and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document will provide additional details on the logic and particular calculations for each of these steps. These include the decline analysis, economic analysis, timing decisions, project selection, constraints, and modeling of technology.

Known Fields

In this step, the production from existing crude oil and natural gas projects is determined. A detailed economic analysis is conducted in order to calculate the economically viable production as well as the expected life of the project. The project life is used to determine when the project becomes eligible for EOR and ASR processes.

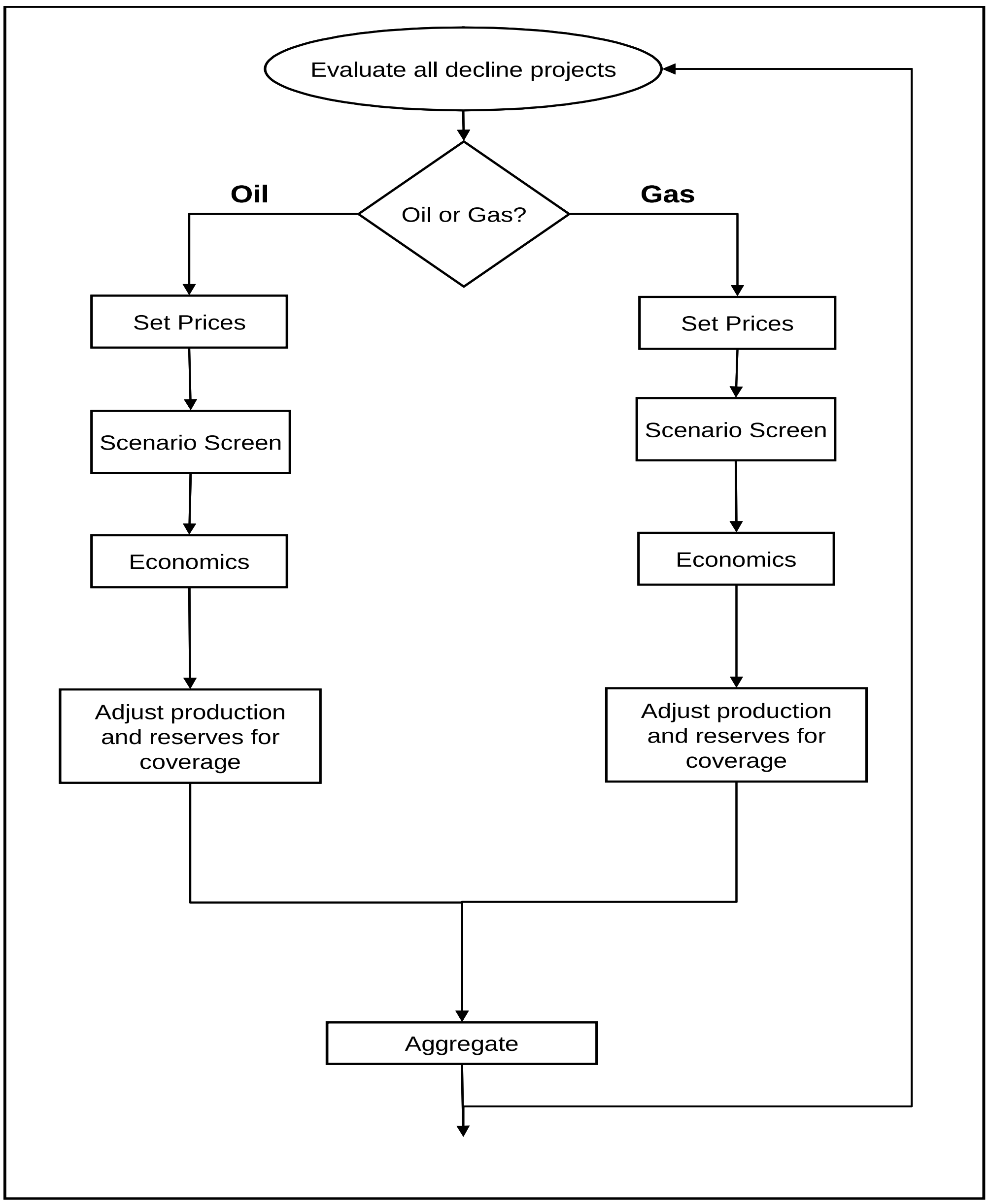
The logic for this process is provided in figure 2-4. For each crude oil project, regional prices are set and the project is screened to determine whether any technology and/or economic levers are applicable. The screening considers factors including region, process, depth, and several other petro-physical properties. After applicable levers are determined, the project undergoes a detailed economic analysis.

After the analysis, resource coverage factors are applied to the economic production and reserves, and the project results are aggregated at the regional and national levels. In a final step, key parameters including the economic lifespan of the project are stored. A similar process is applied to the existing natural gas fields and reservoirs.

Resource coverage factors are applied in the model to ensure that historical production from existing fields matches that reported by EIA. These factors are calculated at the regional level and applied to the following resources:

- Crude oil (includes lease condensates)
- High-permeability natural gas
- Coalbed methane
- Shale gas
- Tight gas

Figure 2-4: Decline Process Flowchart



Economics

Project Costs

OLOGSS conducts the economic analysis of the project using regional crude oil and natural gas prices. After these prices are set, the model evaluates the base and advanced technology cases for the project. The base case is defined as the current technology and cost scenario for the project; while the advanced case includes technology and/or cost improvements associated with the application of model levers. It is important to note that these cases – which are applied to the project – are not the same as the *AEO* low, reference, or high technology cases.

For each technology case, the necessary petro-physical properties and other project data are set, the regional dryhole rates are determined, and the process specific depreciation schedule is assigned. The capital and operating costs for the project are then calculated and aggregated for both the base and advanced technology cases.

In the next step, a standard cashflow analysis is conducted, the discounted rate of return is calculated, and the ranking criteria are set for the project. Afterwards, the number and type of wells required for the project, and the last year of actual economic production are set. Finally, the economic variables, including production, development requirements, and other parameters, are stored for project timing and aggregation. All of these steps are illustrated in figure 2-5.

The details of the calculations used in conducting the economic analysis of a project are provided in the following description.

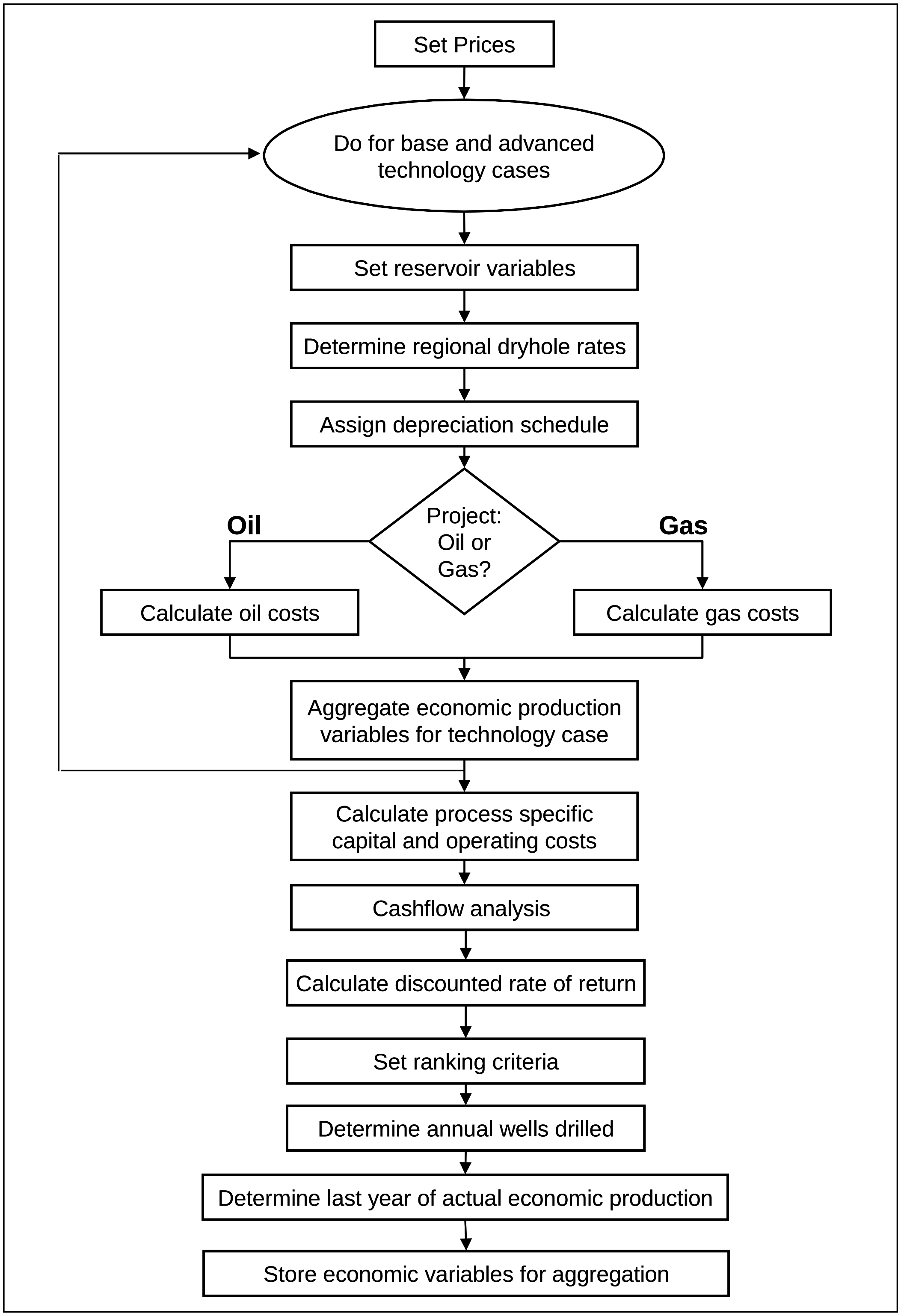
Determine the project shift: The first step is to determine the number of years the project development is shifted. This will be used to determine the crude oil and natural gas price shift. The number of years is dependent upon both the development schedule – when the project drilling begins – and upon the process. The project shift is used to model any delay between the discovery of a project and the start of its development.

Determine annual prices: Determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use a rolling five-year average of historic prices from 1995 to 2008.

Begin analysis of base and advanced technology: To capture the impacts of technology improvements on both production and economics, the model divides the project into two cases. The first case – base technology – does not include improvements associated with technology or economic levers. The second case – advanced technology – incorporates the impact of the levers. The division of the project is dependent upon the market penetration algorithm of any applicable technologies.

Determine the dryhole rate for the project: Assigns the regional dryhole rates for undiscovered exploration, undiscovered development, and discovered development. Three types of dryhole rates are used in the model: development in known fields and reservoirs, the first (wildcat) well in an exploration project, and subsequent wells in an exploration project. Specific dryhole rates are used for horizontal drilling and the developing natural gas resources.

Figure 2-5: Economic Analysis Logic



In the advanced case, the dryhole rates may also incorporate technology improvements associated with exploration or drilling success.

$$REGDRYUE_{im} = \left(\frac{SUCEXP_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) * EXPLR\_FAC_{itech} \tag{2-1}$$

$$REGDRYUD_{im} = \left(\frac{SUCEXPD_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-2}$$

$$REGDRYKD_{im} = \left(\frac{SUCDEVE_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-3}$$

If evaluating horizontal continuity or horizontal profile, then,

$$REGDRYKD_{im} = \left(\frac{SUCCHDEV_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-4}$$

If evaluating developing natural gas resources, then,

$$REGDRYUD_{im} = ALATNUM_{ires} * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-5}$$

Where,

ITECH	=	Technology case number
IM	=	Region number
REGDRYUE	=	Project specific dryhole rate for undiscovered exploration (Wildcat)
REGDRYUD	=	Project specific dryhole rate for undiscovered development
REGDRYKD	=	Project specific dryhole rate for known field development
SUCEXPD	=	Regional dryhole rate for undiscovered development
ALATNUM	=	Variable representing the regional dryhole rate for known field development
SUCDEVE	=	Regional dryhole rate for undiscovered exploration (Wildcat)
SUCCDEVH	=	Dryhole rate for horizontal drilling
DRILL_FAC	=	Technology lever applied to dryhole rate
EXPLR_FAC	=	Technology factor applied to exploratory dryhole rate

Process specific depreciation schedule: The default depreciation schedule is based on an eight-year declining balance depreciation method. The user may select process specific depreciation schedules for CO2 flooding, steam flooding, or water flooding in the input file.

Calculate the capital and operating costs for the project: The project costs are calculated for each technology case. The costs are specific to crude oil or natural gas resources. The results of the cost calculations, which include technical crude oil and natural gas production, as well as drilling costs, facilities costs, and operating costs, are then aggregated to the project level.

G & G factor: Calculates the geological and geophysical (G&G) factor for each technology case. This is added to the first year cost.

$$GG_{\text{itech}} = GG_{itech} + DRL\_CST_{itech} * INTANG\_M_{itech} * GG\_FAC \tag{2-6}$$

Where,

GG_{itech}	=	Geophysical and Geological costs for the first year of the project
DRL_CST_{itech}	=	Total drilling cost for the first year of the project
$INTANG\_M_{itech}$	=	Energy Elasticity factor for intangible investments (first year)
GG_FAC	=	Portion of exploratory costs that is G&G costs

After the variables are aggregated, the technology case loop ends. At this point, the process specific capital costs, which apply to the entire project instead of the technology case, are calculated.

Cashflow Analysis: The model then conducts a cashflow analysis on the project and calculates the discounted rate of return. Economic Analysis is conducted using a standard cashflow routine described in Appendix A.

Calculate the discounted rate of return: Determines the rate of return for all investments and production. The cumulative investments and discounted after tax cashflow are used to calculate the investment efficiency for the project.

Calculate wells: The annual number of new and existing wells is calculated for the project. There are five drilling categories tracked by the model:

- New production wells drilled
- New injection wells drilled
- Active production wells
- Active injection wells
- Shut in wells

The calculation of the annual well count is dependent upon the number of existing production and injection wells as well as the process and project specific requirements to complete each drilling pattern developed.

Determine number of years a project is economic: The model calculates the last year of actual economic production. This is based upon both the results of the cashflow analysis and upon the annual production in year specified by the analysis. The last year of production is used to determine the aggregation range to be used if the project is selected for development.

If the project is economic only in the first year, it will be considered uneconomic and unavailable for development at that time. If this occurs for an existing crude oil or natural gas project, all of the wells will be shut in by the model.

Non-producing decline project: Determines if the existing crude oil or natural gas project is non-producing. If there is no production, then the end point for project aggregation is not calculated. This check applies only to the existing crude oil and natural gas projects

Ranking criteria: Ranks investment efficiency based on the discounted after tax cashflow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion is the parameter by which the projects will be sorted before development. The ranking criterion is specified by the user. The ranking criteria options include the project net present value, the rate of return for the project, and the investment efficiency.

Calculating Unit Costs

To conduct the cost analysis, the model calculates price adjustment factors, and calculates the unit costs for all required capital and operating costs. Unit costs include the cost of drilling and completing a single well, producing one barrel of crude oil, or operating one well for a year. These costs are adjusted using the technology levers and CPI indices. After the development schedule for the project is determined and the economic life of a single well is calculated, the technical production and injection are determined for the project. Based upon the project's development schedule and the technical production, the annual capital and operating costs are determined. In the final step, the process and resource specific capital and operating costs are calculated for the project. These steps are illustrated in figure 2-6.

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. There are three broad categories of costs used by the model: capital costs, operating costs, and other costs. These costs are illustrated in figure 2-7. Capital costs encompass the costs of drilling and equipment necessary for the production of crude oil and natural gas resources. Operating costs are used to calculate the full life cycle economics of the project. Operating costs consist of normal daily expenses and surface maintenance. Other cost parameters include royalty, state and federal taxes, and other required schedules and factors.

The calculations for capital costs and operating costs for both crude oil and natural gas are described in detail. The capital and operating costs are used in the timing and economic module to calculate the lifecycle economics for all crude oil and natural gas projects.

There are two categories for these costs: costs that are applied to all processes, thus defined as resource independent, and the process specific costs, or resource dependent. Process specific costs, or resource dependent, are used to calculate the economics for existing, reserves growth, and exploration projects. The capital costs for both crude oil and natural gas are calculated first, followed by the annual and operating costs for resource independent, and then the resource dependent costs are calculated and applied.

The resource independent and resource dependent costs applied to each of the crude oil and natural gas processes are detailed in tables 2-2 and 2-3 respectively.

Figure 2-6: Project Cost Calculation Procedure

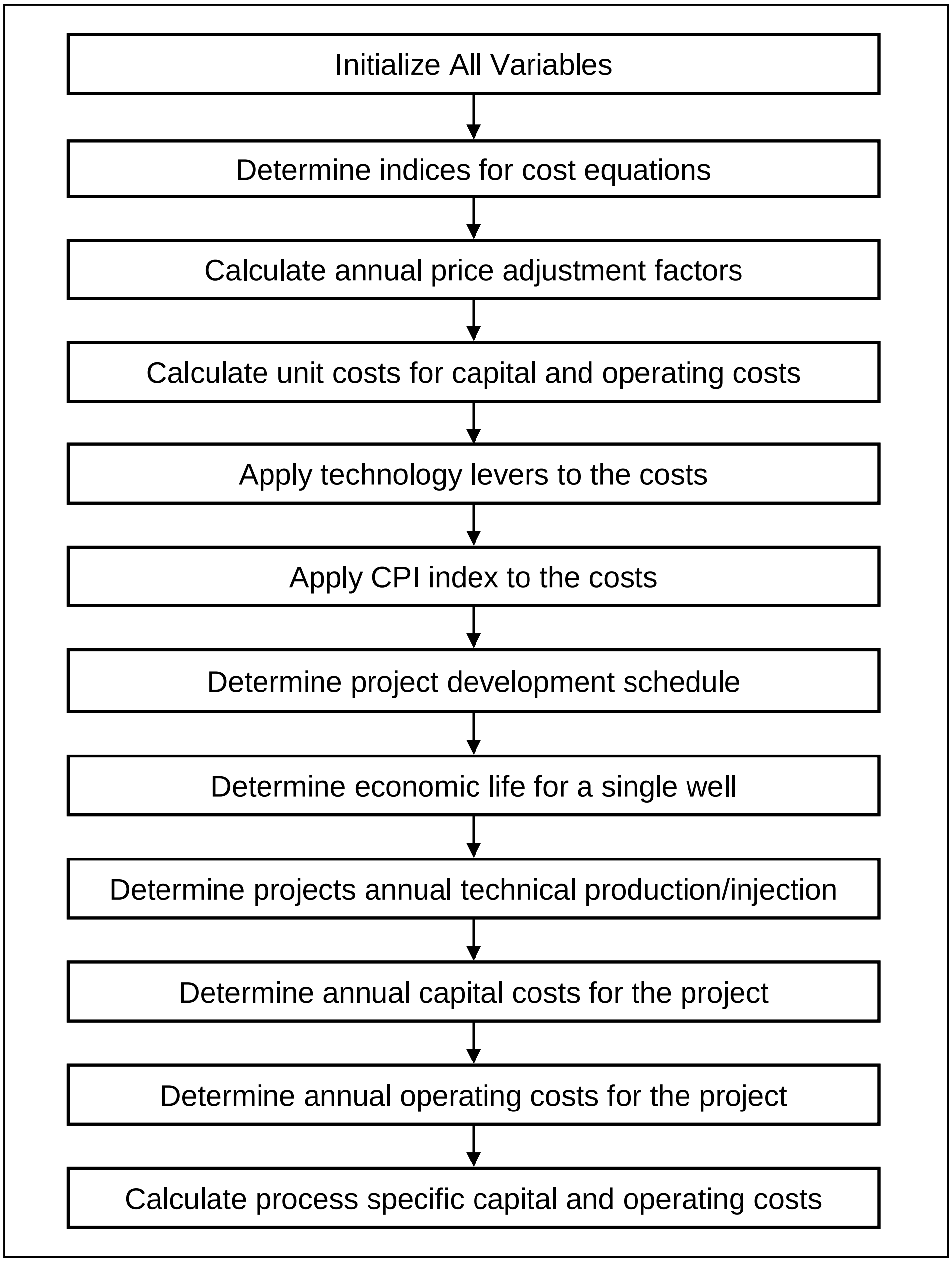


Figure 2-7: Cost Data Types and Requirements

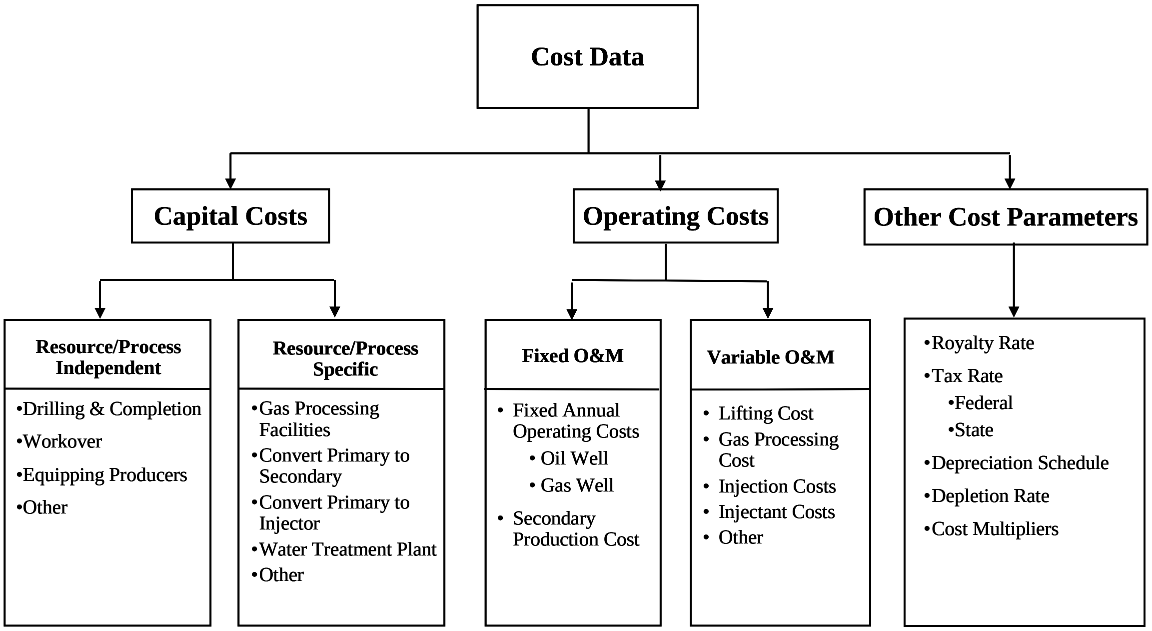


Table 2-2: Costs Applied to Crude Oil Processes

	Capital Cost for Oil	Existing	Water Flooding	CO2 Flooding	Steam Flooding	Polymer Flooding	Infill Drilling	Profile Modification	Undiscovered
Resource Independent	Vertical Drilling Cost	v	v	v	v	v	v	v	v
	Horizontal Drilling Cost								
	Drilling Cost for Dryhole	v	v	v	v	v	v	v	v
	Cost to Equip a Primary Producer		v	v	v	v	v	v	v
	Workover Cost		v	v	v	v	v	v	v
	Facillities Upgrade Cost		v	v	v	v	v	v	
	Fixed Annual Cost for Oil Wells	v	v	v	v	v	v	v	v
	Fixed Annual Cost for Secondary Production		v	v	v	v	v	v	v
	Lifting Cost		v	v	v	v	v	v	v
	O & M Cost for Active Patterns		v			v		v	
	Variable O & M Costs	v	v	v	v	v	v	v	v
	Socondary Workover Cost		v	v	v	v	v	v	v
Resource Dependent	Cost of Water Handling Plant		v			v		v	
	Cost of Chemical Plant					v			
	CO2 Recycle Plant			v					
	Cost of Injectant					v			
	Cost to Convert a Primary to Secondary Well		v	v	v	v	v	v	v
	Cost to Convert a Producer to an Injector		v	v	v	v	v	v	v
	Fixed O & M Cost for Secondary Operations		v	v	v	v	v	v	v
	Cost of a Water Injection Plant		v						
	O & M Cost for Active Patterns per Year		v			v		v	
	Cost to Inject CO2			v					
	King Factor				v				
	Steam Manifolds Cost				v				
	Steam Generators Cost				v				
	Cost to Inject Poloymer					v		v	

Table 2-3: Costs Applied to Natural Gas Processes

	Capital Costs for Gas	Conventional Radial Gas	Water Drive	Tight Sands	Coal/Shale Gas	Undiscovered Conventional
Resource Independent	Vertical Drilling Cost	v	v	v	v	v
	Horizontal Drilling Cost	v	v	v	v	v
	Drilling Cost for Dryhole	v	v	v	v	v
	Gas Facilities Cost	v	v	v	v	v
	Fixed Annual Costs for Gas Wells	v	v	v	v	v
	Gas Stimulation Costs	v	v	v	v	v
	Overhead Costs	v	v	v	v	v
	Variable O & M Cost	v	v	v	v	v
Resource Dependent	Gas Processing and Treatment Facilities	v	v	v	v	v

The following section details the calculations used to calculate the capital and operating costs for each crude oil and natural gas project. The specific coefficients are econometrically estimated according to the corresponding equations in Appendix 2.B.

Cost Multipliers

Cost multipliers are used to capture the impact on capital and operating costs associated with changes in energy prices. OLOGSS calculates cost multipliers for tangible and intangible investments, operating costs, and injectants (polymer and CO_2). The methodology used to calculate the multipliers is based on the National Energy Technology Laboratory (NETL's) Comprehensive Oil and Gas Analysis Model as well as the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.

The multipliers for operating costs and injectant are applied while calculating project costs. The investment multipliers are applied during the cashflow analysis. The injectant multipliers are held constant for the analysis period while the others vary with changing crude oil and natural gas prices.

Operating Costs for Crude Oil: Operating costs are adjusted by the change between current crude oil prices and the base crude oil price. If the crude oil price in a given year falls below a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price.

$$\mathrm{TERM} = \left(\frac{\mathrm{OILPRICE}_{iyr} - \mathrm{BASEOIL}}{\mathrm{BASEOIL}}\right) \tag{2-7}$$

$$\mathrm{INTANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_INT} * \mathrm{TERM}) \tag{2-8}$$
$$\mathrm{TANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_TANG} * \mathrm{TERM}) \tag{2-9}$$
$$\mathrm{OAM\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_OAM} * \mathrm{TERM}) \tag{2-10}$$

Where,

IYR	=	Year
TERM	=	Fractional change in crude oil prices
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
OMULT_INT	=	Coefficient for intangible crude oil investment factor
OMULT_TANG	=	Coefficient for tangible crude oil investment factor
OMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Natural Gas:

$$TERM = \left(\frac{GASPRICEC_{iyr} - BASEGAS}{BASEGAS} \right) \quad (2\text{-}11)$$

$$TANG\_M_{iyr} = 1.0 + (GMULT\_TANG * TERM) \quad (2\text{-}12)$$

$$INTANG\_M_{iyr} = 1.0 + (GMULT\_INT * TERM) \quad (2\text{-}13)$$

$$OAM\_M_{iyr} = 1.0 + (GMULT\_OAM * TERM) \quad (2\text{-}14)$$

Where,

GASPRICEC	=	Annual natural gas price
IYR	=	Year
TERM	=	Fractional change in natural gas prices
BASEGAS	=	Base natural gas price used for normalization of capital and operating costs
GMULT_INT	=	Coefficient for intangible natural gas investment factor
GMULT_TANG	=	Coefficient for tangible natural gas investment factor
GMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Injectant:

In the first year of the project:

$$FPLY = 1.0 + (0.3913 * TERM) \quad (2\text{-}15)$$

$$FCO2 = \frac{0.5 + 0.013 * BASEOIL * (1.0 + TERM)}{0.5 + 0.013 * BASEOIL} \quad (2\text{-}16)$$

Where,

TERM	=	Fractional change in crude oil prices
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs

FPLY	=	Energy elasticity factor for polymer
FCO2	=	Energy elasticity factor for natural CO_2 prices

Resource Independent Capital Costs for Crude Oil

Resource independent capital costs are applied to both crude oil and natural gas projects, regardless of the recovery method applied. The major resource independent capital costs are: drilling and completion costs, the cost to equip a new or primary producer, and workover costs.

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost to drill a dryhole/wildcat during exploration. OLOGSS will have separate costs for dryholes drilled, documented below. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Whereas, the horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Horizontal Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH^2) + (OIL\_DWCB_{r,d} * DEPTH^2 * NLAT) + (OIL\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \tag{2-17}$$

Vertical Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH) + (OIL\_DWCB_{r,d} * DEPTH^2) + (OIL\_DWCC_{r,d} * DEPTH^3) \tag{2-18}$$

Where,

DWC_W	=	Cost to drill and complete a crude oil well (K$/Well)
R	=	Region number
D	=	Depth category number
OIL_DWCA, B, C, K	=	Coefficients for crude oil well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Horizontal Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \tag{2-19}$$

Vertical Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \tag{2-20}$$

Where,

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Cost to Equip a New Producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W = NPRK_{r,d} + (NPRA_{r,d} * DEPTH) + (NPRB_{r,d} * DEPTH^2) + (NPRC_{r,d} * DEPTH^3) \tag{2-21}$$

Where,

NPR_W	=	Cost to equip a new producer (K$/Well)
R	=	Region number
D	=	Depth category number
NPRA, B, C, K	=	Coefficients for new producer equipment cost equation
DEPTH	=	Well depth

Workover Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W = WRKK_{r,d} + (WRKA_{r,d} * DEPTH) + (WRKB_{r,d} * DEPTH^2) + (WRKC_{r,d} * DEPTH^3) \tag{2-22}$$

Where,

WRK_W	=	Cost for a well workover (K$/Well)
R	=	Region number
D	=	Depth category number
WRKA, B, C, K	=	Coefficients for workover cost equation
DEPTH	=	Well depth

Facilities Upgrade Cost: Additional cost of equipment upgrades when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W = FACUPK_{r,d} + (FACUPA_{r,d} * DEPTH) + (FACUPB_{r,d} * DEPTH^2) + (FACUPC_{r,d} * DEPTH^3) \tag{2-23}$$

Where,

FAC_W	=	Well facilities upgrade cost (K$/Well)
R	=	Region number
D	=	Depth category number
FACUPA, B, C, K	=	Coefficients for well facilities upgrade cost equation

DEPTH	=	Well depth

Resource Independent Capital Costs for Natural Gas

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost to drill a dryhole/wildcat during exploration. OLOGSS will have separate costs for dryholes drilled, documented below. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Whereas, the horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Vertical Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH) + (GAS\_DWCB_{r,d} * DEPTH^2) + (GAS\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}24)$$

Horizontal Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH^2) + (GAS\_DWCB_{r,d} * DEPTH^2 * NLAT) + (GAS\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}25)$$

Where,

DWC_W	=	Cost to drill and complete a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
GAS_DWCA, B, C, K	=	Coefficients for natural gas well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Vertical Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}26)$$

Horizontal Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}27)$$

Where,

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Facilities Cost: Additional cost of equipment upgrades when converting a primary producing well to a secondary resource recovery producing well. Facilities costs consist of flowlines and connections, production package costs, and storage tank costs.

$$FWC\_W_{iyr} = FACGK_{r,\,d} + (FACGA_{r,\,d} * DEPTH) + (FACGB_{r,\,d} * PEAKDAILY\_RATE) + (FACGC_{r,\,d} * DEPTH * PEAKDAILY\_RATE) \qquad (2\text{-}28)$$

Where,

FWC_W	=	Facilities cost for a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
FACGA, B, C, K	=	Coefficients for facilities cost equation
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Fixed Annual Operating Costs: The fixed annual operating costs will be applied to natural gas projects in decline curve analysis.

$$FOAMG\_W = OMGK_{r,\,d} + (OMGA_{r,\,d} * DEPTH) + (OMGB_{r,\,d} * PEAKDAILY\_RATE) + (OMGC_{r,\,d} * DEPTH * PEAKDAILY\_RATE) \qquad (2\text{-}29)$$

Where,

FOAMG_W	=	Fixed annual operating costs for natural gas (K$/Well)
R	=	Region number
D	=	Depth category number
OMGA, B, C, K	=	Coefficients for fixed annual O & M cost equation for natural gas
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Resource Independent Annual Operating Costs for Crude Oil

Fixed Operating Costs: The fixed annual operating costs will be applied to crude oil projects in decline curve analysis.

$$OMO\_W = OMOK_{r,\,d} + (OMOA_{r,\,d} * DEPTH) + (OMOB_{r,\,d} * DEPTH^2) + (OMOC_{r,\,d} * DEPTH^3) \qquad (2\text{-}30)$$

Where,

OMO_W	=	Fixed annual operating costs for crude oil wells (K$/Well)
R	=	Region number
D	=	Depth category number
OMOA, B, C, K	=	Coefficients for fixed annual operating cost equation for crude oil
DEPTH	=	Well depth

Annual Costs for Secondary Producers: The direct annual operating expenses include costs in the following major areas: normal daily expenses, surface maintenance, and subsurface maintenance.

$$OPSEC\_W = OPSECK_{r,\,d} + (OPSECA_{r,\,d} * DEPTH) + (OPSECB_{r,\,d} * DEPTH^2) + (OPSECC_{r,\,d} * DEPTH^3) \quad (2\text{-}31)$$

Where,

OPSEC_W	=	Fixed annual operating cost for secondary oil operations (K$/Well)
R	=	Region number
D	=	Depth category number
OPSECA, B, C, K	=	Coefficients for fixed annual operating cost for secondary oil operations
DEPTH	=	Well depth

Lifting Costs: Incremental costs are added to a primary and secondary flowing well. These costs include pump operating costs, remedial services, workover rig services and associated labor.

$$OML\_W = OMLK_{r,\,d} + (OMLA_{r,\,d} * DEPTH) + (OMLB_{r,\,d} * DEPTH^2) + (OMLC_{r,\,d} * DEPTH^3) \quad (2\text{-}32)$$

Where,

OML_W	=	Variable annual operating cost for lifting (K$/Well)
R	=	Region number
D	=	Depth category number
OMLA, B, C, K	=	Coefficients for variable annual operating cost for lifting equation
DEPTH	=	Well depth

Secondary Workover: Secondary workover, also known as stimulation is done every 2-3 years to increase the productivity of a secondary producing well. In some cases secondary workover or stimulation of a wellbore is required to maintain production rates.

$$SWK\_W = OMSWRK_{r,\,d} + (OMSWR\ A_{r,\,d} * DEPTH) + (OMSWR\ B_{r,\,d} * DEPTH^2) + (OMSWR\ C_{r,\,d} * DEPTH^3) \quad (2\text{-}33)$$

Where,

SWK_W	=	Secondary workover costs (K$/Well)
R	=	Region number
D	=	Depth category number
OMSWRA, B, C, K	=	Coefficients for secondary workover costs equation
DEPTH	=	Well depth

Stimulation Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$STIM\_W = \left(\frac{STIM\_A + STIM\_B * DEPTH}{1000}\right) \tag{2-34}$$

Where,

STIM_W	=	Oil stimulation costs (K$/Well)
STIM_A, B	=	Stimulation cost equation coefficients
DEPTH	=	Well depth

Resource Dependent Capital Costs for Crude Oil

Cost to Convert a Primary Well to a Secondary Well: These costs consist of additional costs to equip a primary producing well for secondary recovery. The cost of replacing the old producing well equipment includes costs for drilling and equipping water supply wells but excludes tubing costs.

$$PSW\_W = PSWK_{r,d} + (PSWA_{r,d} * DEPTH) + (PSWB_{r,d} * DEPTH^2) + (PSWC_{r,d} * DEPTH^3) \tag{2-35}$$

Where,

PSW_W	=	Cost to convert a primary well into a secondary well (K$/Well)
R	=	Region number
D	=	Depth category number
PSWA, B, C, K	=	Coefficients for primary to secondary well conversion cost equation
DEPTH	=	Well depth

Cost to Convert a Producer to an Injector: Producing wells may be converted to injection service because of pattern selection and favorable cost comparison against drilling a new well. The conversion procedure consists of removing surface and sub-surface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2- 7/8 inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$PSI\_W = PSIK_{r,d} + (PSIA_{r,d} * DEPTH) + (PSIB_{r,d} * DEPTH^2) + (PSIC_{r,d} * DEPTH^3) \tag{2-36}$$

Where,

PSI_W	=	Cost to convert a producing well into an injecting well (K$/Well)
R	=	Region number
D	=	Depth category number
PSIA, B, C, K	=	Coefficients for producing to injecting well conversion cost equation
DEPTH	=	Well depth

Cost of Produced Water Handling Plant: The capacity of the water treatment plant is a function of the maximum daily rate of water injected and produced (MBbl) throughout the life of the project.

$$\text{PWP\_F} = \text{PWHP} * \left(\frac{\text{RMAXW}}{365}\right) \tag{2-37}$$

Where,

PWP_F	=	Cost of the produced water handling plant (K$/Well)
PWHP	=	Produced water handling plant multiplier
RMAXW	=	Maximum pattern level annual water injection rate

Cost of Chemical Handling Plant (Non-Polymer): The capacity of the chemical handling plant is a function of the maximum daily rate of chemicals injected throughout the life of the project.

$$\text{CHM\_F} = \text{CHMK} * \text{CHMA} * \left(\frac{\text{RMAXP}}{365}\right)^{\text{CHMB}} \tag{2-38}$$

Where,

CHM_F	=	Cost of chemical handling plant (K$/Well)
CHMB	=	Coefficient for chemical handling plant cost equation
CHMK, A	=	Coefficients for chemical handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of Polymer Handling Plant: The capacity of the polymer handling plant is a function of the maximum daily rate of polymer injected throughout the life of the project.

$$\text{PLY\_F} = \text{PLYPK} * \text{PLYPA} * \left(\frac{\text{RMAXP}}{365}\right)^{0.6} \tag{2-39}$$

Where,

PLY_F	=	Cost of polymer handling plant (K$/Well)
PLYPK, A	=	Coefficients for polymer handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of CO_2 Recycling Plant: The capacity of a recycling/injection plant is a function of the maximum daily injection rate of CO_2 (Mcf) throughout the project life. If the maximum CO_2 rate is equal or greater to 60 MBbl/Day then the costs are divided into two separate plant costs.

$$\text{CO2\_F} = \text{CO2rk} * \left(\frac{0.75 * \text{RMAXP}}{365}\right)^{\text{CO2RB}} \tag{2-40}$$

Where,

CO2_F	=	Cost of CO_2 recycling plant (K$/Well)
CO2RK, CO2RB	=	Coefficients for CO_2 recycling plant cost equation
RMAXP	=	Maximum pattern level annual CO_2 injection rate

Cost of Steam Manifolds and Pipelines: Cost to install and maintain steam manifolds and pipelines for steam flood enhanced oil recovery project.

$$STMM\_F = TOTPAT * PATSZE * STMMA \tag{2-41}$$

Where,

STMM_F	=	Cost for steam manifolds and generation (K$)
TOTPAT	=	Total number of patterns in the project
PATSZE	=	Pattern size (Acres)
STMMA	=	Steam manifold and pipeline cost (per acre)

Resource Dependant Annual Operating Costs for Crude Oil

Injection Costs: Incremental costs are added to secondary injection wells. These costs include pump operating, remedial services, workover rig services, and associated labor.

$$OPINJ\_W = OPINJK_{r,\,d} + (OPINJA_{r,\,d} * DEPTH) + (OPINJ\ B_{r,\,d} * DEPTH^2) + (OPINJ\ C_{r,\,d} * DEPTH^3) \tag{2-42}$$

Where,

OPINJ_W	=	Variable annual operating cost for injection (K$/Well)
R	=	Region number
D	=	Depth category number
OPINJA, B, C, K	=	Coefficients for variable annual operating cost for injection equation
DEPTH	=	Well depth

Injectant Cost: The injectant costs are added to the secondary injection wells. These costs are specific to the recovery method selected for the project. Three injectants are modeled: polymer, CO_2 from natural sources, and CO_2 from industrial sources.

Polymer Cost:

$$POLYCOST = POLYCOST * FPLY \tag{2-43}$$

Where,

POLYCOST	=	Cost of polymer ($/Lb)
FPLY	=	Energy elasticity factor for polymer

Natural CO_2 Cost: Cost to drill, produce and ship CO_2 from natural sources, namely CO_2 fields in Western Texas.

$$CO2COST = CO2K + (CO2B * OILPRICEO(1)) \tag{2-44}$$

$$CO2COST = CO2COST * CO2PR(IST) \tag{2-45}$$

Where,

CO2COST	=	Cost of natural CO_2 ($/Mcf)
IST	=	State identifier
CO2K, CO2B	=	Coefficients for natural CO_2 cost equation
OILPRICEO(1)	=	Crude oil price for first year of project analysis
CO2PR	=	State CO_2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO_2 Cost: Cost to capture and transport CO_2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site via pipeline. The regional costs are exogenously determined and are specific to the industrial source of CO_2 and are provided in the input file.

Industrial CO_2 Sources include

- Hydrogen Plants
- Ammonia Plants
- Existing and Planned Ethanol Plants
- Cement Plants
- Refineries
- Fossil Fuel Plants
- Integrated Gasification Combined Cycle (IGCC) Plants

After unit costs have been calculated for the project, they are adjusted using technology levers as well as CPI multipliers. Two types of levers are applied to the costs. The first is the fractional change in cost associated with a new technology. The second is the incremental cost associated with implementing the new technology. These factors are determined by the model user. As an example,

$$NPR\_W = (NPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \quad (2\text{-}46)$$

Where,

NPR_W	=	Cost to equip a new oil producer (K$/well)
CHG_FAC_FAC	=	Fractional change in cost associated with technology improvements
CST_FAC_FAC	=	Incremental cost to apply the new technology
ITECH	=	Technology case (Base or Advanced)

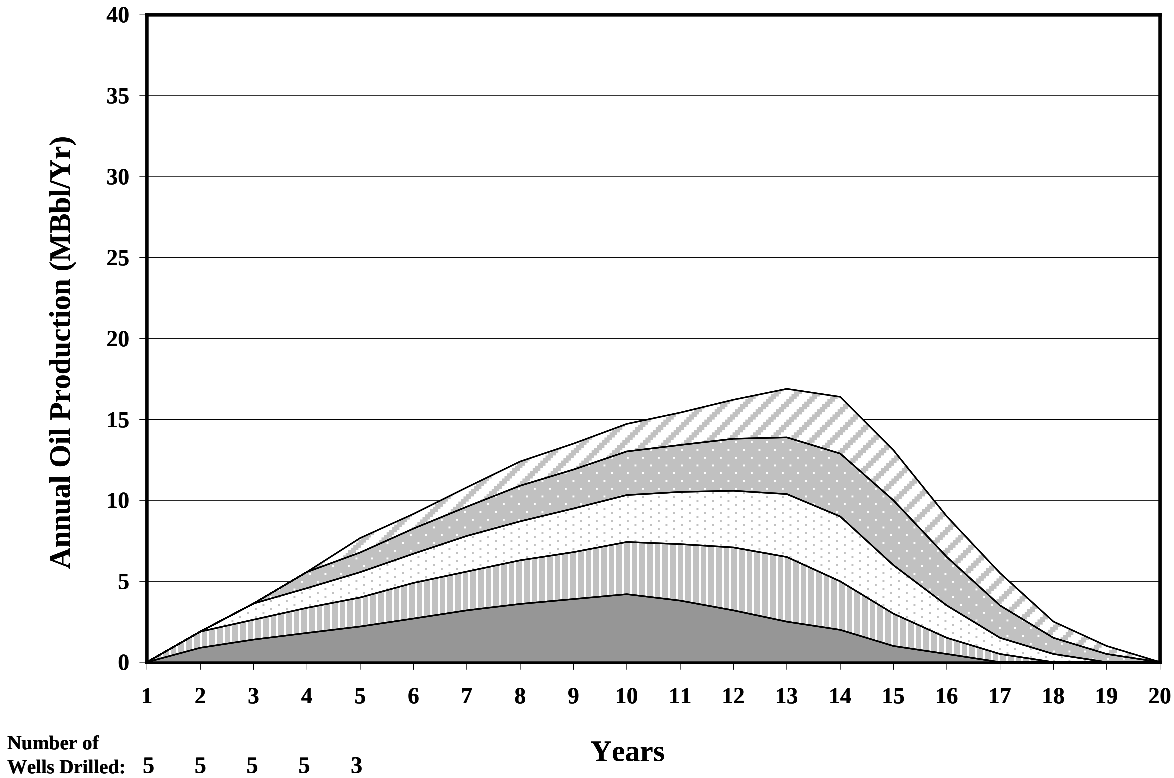
Determining Technical Production

The development schedule algorithms determine how the project will be developed over time, the number of patterns initiated per year and the economic life of the well. The economic life is the number of years in which the revenue from production exceeds the costs required to produce the crude oil and natural gas.

The model then aggregates the well-level production of crude oil, natural gas, water, and injectant based upon the pattern life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-8 shows the crude oil production for one project over the course of its life. The graph shows a hypothetical project. In this scenario patterns are initiated for five years. Each shaded area is the annual technical production associated with the initiated patterns.

Figure 2-8: Calculating Project Level Technical Production



The first step in determining the technical production is to calculate the number of patterns drilled each year. The model uses several factors in calculating the development schedule:

- Potential delays between the discovery of the project and actual initiation
- The process modeled
- The resource access – the number of patterns developed each year is reduced if the resource is subject to cumulative surface use limitations
- The total number of patterns in the project
- The crude oil and natural gas prices
- The user specified maximum and minimum number of patterns developed each year
- The user specified percentage of the project to be developed each year
- The percentage of the project which is using base or advanced technology.

These apply to the EOR/ASR projects as well as the undiscovered and currently developing ones. The projects in existing fields and reservoirs are assumed to have all of their patterns – the number of active wells – developed in the first year of the project.

After determining the number of patterns initiated each year, the model calculates the number of patterns which are active for each year of the project life.

Production Profile of the Project: For all EOR/ASR, undiscovered, and developing processes, the project level technical production is calculated using well-level production profiles. For infill projects, the production is doubled because the model assumes that there are two producers in each pattern.

$$OILPROD_{iyr1} = OILPROD_{iyr1} + (OPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}47)$$
$$GASPROD_{iyr1} = OILPROD_{iyr1} + (GPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}48)$$
$$NGLPROD_{iyr1} = NGLPROD_{iyr1} + (NPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}49)$$
$$WATPROD_{iyr1} = WATPROD_{iyr1} + (WPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}50)$$
$$TOTINJ_{iyr1} = TOTINJ_{iyr1} + (OINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}51)$$
$$WATINJ_{iyr1} = WATINJ_{iyr1} + (WINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}52)$$
$$TORECY_{iyr1} = TORECY_{iyr1} + (ORECY_{kyr} * PATN_{iyr}) \quad (2\text{-}53)$$
$$SUMP_{iyr1} = SUMP_{iyr1} + PATN_{iyr} \quad (2\text{-}54)$$

Where,

IYR1	=	Number of years
IYR	=	Year of project development
JYR	=	Number of years the project is developed
KYR	=	Year (well level profile)
LYR	=	Last project year in which pattern level profile is applied
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
NPROD	=	Pattern level annual NGLl production
WPROD	=	Pattern level annual water production
WINJ	=	Pattern level annual water injection
OINJ	=	Pattern level annual injectant injection
ORECY	=	Pattern level annual injectant recycled
PATN	=	Number of patterns initiated each year
SUMP	=	Cumulative number of patterns developed
OILPROD	=	Project level annual crude oil production
GASPROD	=	Project level annual natural gas production
NGLPROD	=	Project level annual NGL production
WATPROD	=	Project level annual water production
WATINJ	=	Project level annual water injection
TOTINJ	=	Project level annual injectant injection
TORECY	=	Project level annual injectant recycled

Resource Accounting

OLOGSS incorporates a complete and representative description of the processes by which crude oil and natural gas in the technically recoverable resource base[1] convert to proved reserves.[2]

OLOGSS distinguishes between drilling for new fields (new field wildcats) and that for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in

[1]*Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[2]*Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions.

End of Year Reserves: The model calculates two types of end of year (EOY) reserves at the project level: inferred reserves and proved reserves. Inferred reserves are calculated as the total technical production minus the technical production from patterns initiated through a particular year. Proved reserves are calculated as the technical production from wells initiated through a particular year minus the cumulative production from those patterns.

Inferred reserves = total technical production – technical production for wells initiated

$$\text{airsvoil(ires, n)} = \sum_{`i=1}^{max\_yr}\left[\sum_{j=1}^{ilife}(\text{oprod}(j))\times \text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{oprod}(j))\times \text{patn}(i)\right] \tag{2-55}$$

$$\text{airsvgas(ires, n)} = \sum_{`i=1}^{max\_yr}\left[\sum_{j=1}^{ilife}(\text{gprod}(j))\times \text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{gprod}(j))\times \text{patn}(i)\right] \tag{2-56}$$

Proved reserves = technical production for patterns initiated – cumulative production

$$\text{aresvoil(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{oprod}(j))\times \text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\text{oprod}(j))\times \text{patn}(i)\right] \tag{2-57}$$

$$\text{aresvgas(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}(\text{gprod}(j))\times \text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{n}(\text{gprod}(j))\times \text{patn}(i)\right] \tag{2-58}$$

Where,

I, J	=	Years
N	=	Current year evaluated
ILIFE	=	Pattern life
MAX_YR	=	Maximum number of years
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
PATN	=	Number of patterns developed each year
AIRSVOIL	=	Annual inferred crude oil reserves
AIRSVGAS	=	Annual inferred natural gas reserves
ARESVOIL	=	Annual proved oil reserves
ARESVGAS	=	Annual proved natural gas reserves

For existing crude oil and natural gas projects, the model calculates the proved reserves. For these processes, the proved reserves are defined as the total technical production divided by the life of the project.

[3] *Undiscovered resources* are located outside of oil and gas fields, in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4] *Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

Calculating Project Costs

The model uses four drilling categories for the calculation of drilling and facilities costs. These categories are:

- New producers
- New injectors
- Conversions of producers to injectors
- Conversions of primary wells to secondary wells.

The number of each category required for the pattern is dependent upon the process and the project.

Project Level Process Independent Costs

Drilling costs and facility costs are determined at the project level.

Drilling Costs: Drilling costs are calculated with one of four approaches, depending on the resource and recovery process. These approaches apply to:

- Undiscovered crude oil and natural gas
- Existing crude oil and natural gas fields
- EOR/ASR projects
- Developing natural gas projects

For undiscovered crude oil and natural gas resources: the first well drilled in the first year of the project is assumed to be a wildcat well. The remaining wells are assumed to be undiscovered development wells. This is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUE_R) * 1.0 * XPP1 \quad (2\text{-}59)$$

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} - 1 * XPP1) \quad (2\text{-}60)$$

For existing crude oil and natural gas fields: as the field is already established, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATDEV_{ires,iyr,\,itech} * XPP1) \quad (2\text{-}61)$$

For EOR/ASR Projects: as the project is in an established and known field, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}62)$$

For developing natural gas projects: as the project is currently being developed, it is assumed that the wildcat well(s) have previously been drilled. Therefore, the undiscovered developmental dryhole rate is applied to the project.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_{R}) * (PATN_{iyr} * XPP1) \quad (2\text{-}63)$$

Where,

IRES	=	Project index number
IYR	=	Year
R	=	Region
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
PATN	=	Annual number of patterns initiated
DRL_CST2	=	Technology case specific annual drilling cost
DWC_W	=	Cost to drill and complete a well
DRY_W	=	Cost to drill a dryhole
REGDRYUE	=	Dryhole rate for undiscovered exploration (wildcat)
REGDRYUD	=	Dryhole rate for undiscovered development
REGDRYKD	=	Dryhole rate for known fields development
XPP1	=	Number of producing wells drilled per pattern

Facilities Costs: Facilities costs are dependent upon both the process and the resource. Five approaches are used to calculate the facilities costs for the project.

For undiscovered and developing natural gas projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}64)$$

For existing natural gas fields:

$$FACCOST_{iyr} = FACCOST_{iyr} +(FWC\_W * (PATDEV_{IRES,iyr, itech}) * XPP1) \quad (2\text{-}65)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = FACCOST_{iyr} + (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}66)$$

For existing crude oil fields:

$$FACCOST_{iyr} = FACCOST_{iyr} + (PSW\_W * (PATDEV_{IRES,iyr, itech}) * XPP4) + (PSI\_W * PATDEV_{IRES,iyr, itech} * XPP3) + (FAC\_W * PATDEV_{IRES,iyr, itech} * (XPP1 + XPP2)) \quad (2\text{-}67)$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (PSW\_W * PATN_{iyr} *XPP4) + (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2)) \quad (2\text{-}68)$$

Where,

IYR	=	Year

IRES	=	Project index number
ITECH	=	Technology case
PATN	=	Number of patterns initiated each year for the technology case being evaluated
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
XPP1	=	Number of new production wells drilled per pattern
XPP2	=	Number of new injection wells drilled per pattern
XPP3	=	Number of producers converted to injectors per pattern
XPP4	=	Number of primary wells converted to secondary wells per pattern
FAC_W	=	Crude oil well facilities upgrade cost
NPR_W	=	Cost to equip a new producer
PSW_W	=	Cost to convert a primary well to a secondary well
PSI_W	=	Cost to convert a production well to an injection well
FWC_W	=	Natural gas well facilities cost
FACCOST	=	Annual facilities cost for the well

Injectant Cost Added to Operating and Maintenance: The cost of injectant is calculated and will be added to the operating and maintenance costs.

$$INJ_{iyr} = INJ_{iyr} + INJ\_OAM1 * WATINJ_{iyr} \qquad (2\text{-}69)$$

Where,

IYR	=	Year
INJ	=	Annual injection cost
INJ_OAM1	=	Process specific cost of injection ($/Bbl)
WATINJ	=	Annual project level water injection

Fixed Annual Operating Costs for Crude Oil:

For CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + OPSEC\_W * SUMP_{iyr} \qquad (2\text{-}70)$$

For undiscovered conventional crude oil:

Fixed annual operating costs for secondary oil wells are assumed to be zero.

For all crude oil processes except CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \qquad (2\text{-}71)$$

Fixed Annual Operating Costs for Natural Gas:
For existing natural gas fields:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \quad (2\text{-}72)$$

For undiscovered and developing natural gas resources:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \quad (2\text{-}73)$$

Where,

AOAM	=	Annual fixed operating an maintenance costs
IYR	=	Year
SUMP	=	Total cumulative patterns initiated
OPSEC_W	=	Fixed annual operating costs for secondary oil wells
OMO_W	=	Fixed annual operating costs for crude oil wells
FOAMG_W	=	Fixed annual operating costs for natural gas wells
OAM_M	=	Energy elasticity factor for operating and maintenance costs
XPATN	=	Annual number of active patterns
XPP1	=	Number of producing wells drilled per pattern

Variable Operating Costs:

$$OAM_{iyr} = OAM_{iyr} + (OILPROD_{iyr} * OIL\_OAM1 * OAM\_M_{iyr}) + (GASPROD_{iyr} * GAS\_OAM1 * OAM\_M_{iyr}) + (WATPROD_{iyr} * WAT\_OAM1 * OAM\_M_{iyr}) \quad (2\text{-}74)$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \quad (2\text{-}74)$$

For infill drilling: Injectant costs are zero.

$$OAM_{iyr} = OAM_{iyr} + INJ_{iyr} \quad (2\text{-}75)$$

Where,

OAM	=	Annual variable operating and maintenance costs
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water injection
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
STIM	=	Project stimulation costs
STIM_W	=	Well stimulation costs
INJ	=	Cost of injection
XPATN	=	Annual number of active patterns

IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern

Cost of Compression (Natural Gas Processes):
Installation costs:

$$COMP_{IYR} = COMP_{IYR} + (COMP\_W*PATN_{IYR}*XPP1) \tag{2-76}$$

O&M cost for compression:

$$OAM\_COMP_{IYR} = OAM\_COMP_{IYR} + (GASPROD_{IYR} * COMP\_OAM *OAM\_M_{IYR}) \tag{2-77}$$

Where,

COMP	=	Cost of installing natural gas compression equipment
COMP_W	=	Natural gas compression cost
PATN	=	Number of patterns initiated each year
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern
OAM_COMP	=	Operating and maintenance costs for natural gas compression
GASPROD	=	Annual project level natural gas production
COMP_OAM	=	Compressor O & M costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs

Process Dependent Costs

Process-specific facilities and capital costs are calculated at the project level.

Facilities Costs

Profile Model: The facilities cost of a water handling plant are added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \tag{2-78}$$

Where,

$FACCOST_1$	=	First year of project facilities costs
PWHP	=	Produced water handling plant multiplier
RMAX	=	Maximum annual water injection rate

Polymer Model: The facilities cost for a water handling plant are added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \tag{2-79}$$

Where,

$FACCOST_1$	=	First year of project facilities costs
PWP_F	=	Produced water handling plant

Advanced CO_2: Other costs added to the facilities costs include the facilities cost for a CO_2 handling plant and a recycling plant, the O&M cost for a CO_2 handling plant and recycling plant, injectant cost, O&M and fixed O&M costs for a CO_2 handling plant and a recycling plant. If the plant is developed in a single stage, the costs are added to the first year of the facilities costs. If a second stage is required, the additional costs are added to the sixth year of facilities costs.

$$FACCOST1 = FACCOST1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365} \right)^{CO2RB} \right) * 1{,}000 \qquad (2\text{-}80)$$

$$FACCOST6 = FACCOST6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365} \right)^{CO2RB} \right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \qquad (2\text{-}81)$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \qquad (2\text{-}82)$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \qquad (2\text{-}83)$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \qquad (2\text{-}84)$$

Where,

IYR	=	Year
RMAX	=	Maximum annual volume of recycled CO_2
CO2OAM	=	O & M cost for CO_2 handling plant
CO2OAM2	=	The O & M cost for the project's CO_2 injection plant
CO2RK, CO2RB	=	CO_2 recycling plant cost coefficients
INJ	=	Cost of purchased CO_2
TOTINJ	=	Annual project level volume of injected CO_2
TORECY	=	Annual project level CO_2 recycled volume
CO2COST	=	Cost of CO_2 ($/mcf)
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
FOAM	=	Fixed annual operating and maintenance costs
FCO2	=	Energy elasticity factor for CO_2
FACCOST	=	Annual project facilities costs
TORECY_CST	=	The annual cost of operating the CO_2 recycling plant

Steam Model: Facilities and O&M costs for steam generators and recycling.

<u>Recalculate the facilities costs:</u> Facilities costs include the capital cost for injection plants, which is based upon the OOIP of the project, the steam recycling plant, and the steam generators required for the project.

$$FACCOST1 = FACCOST1 + \left(\frac{OOIP * 0.1 * 2.0 * APAT}{TOTPAT}\right) + (RECY\_WAT * RMAXWAT + RECY\_OIL * RMAXOIL) + (STMMA * TOTPAT * PATSIZE) + (IGEN_{iyr} - IG) * STMGA \quad (2\text{-}85)$$

$$OAM_{iyr} = OAM_{iyr} + (WAT\_OAM1 * WATPROD_{iyr} * OAM\_M_{iyr}) + (OIL\_OAM1 * OILPROD_{iyr} * OAM\_M_{iyr}) + (INJ\_OAM1 * WATINJ_{iyr} * OAM\_M_{iyr}) \quad (2\text{-}86)$$

Where,

IYR	=	Year
IGEN	=	Number of active steam generators each year
IG	=	Number of active steam generators in previous year
FACCOST	=	Annual project level facilities costs
RMAXWAT	=	Maximum daily water production rate
RMAXOIL	=	Maximum daily crude oil production rate
APAT	=	Number of developed patterns
TOTPAT	=	Total number of patterns in the project
OOIP	=	Original oil in place (mmbbl)
PATSIZE	=	Pattern size (acres)
STMMA	=	Unit cost for steam manifolds
STMGA	=	Unit cost for steam generators
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
INJ_OAM1	=	Process specific cost of water injection ($/Bbl)
OILPROD	=	Annual project level crude oil production
WATPROD	=	Annual project level water production
WATINJ	=	Annual project level water injection
RECY_WAT	=	Recycling plant cost – water factor
RECY_OIL	=	Recycling plant cost – oil factor

Operating and Maintenance Cost

This subroutine calculates the process specific O&M costs.

Profile Model: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \quad (2\text{-}87)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}88)$$

Where,

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
OAM_M	=	Energy elasticity factor for operating and maintenance

cots

TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Polymer: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1{,}000} \quad (2\text{-}89)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}90)$$

Where,

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Waterflood: Add the O&M costs of water injected as well as the cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}91)$$

Where,

IYR	=	Year
MAX_YR	=	Maximum number of years
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Existing crude oil fields and reservoirs: Since no new drilling or major investments are expected for decline, facilities and drilling costs are zeroed out.

$$OAM_{iyr} = OAM_{iyr} + ((OIL\_OAM1 * OILPROD_{iyr}) + (GAS\_OAM1 * GASPROD_{iyr}) + (WAT\_OAM1 * WATPROD_{iyr})) * OAM\_M_{iyr} \quad (2\text{-}92)$$

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5}\right) \quad (2\text{-}93)$$

Where,

IYR	=	Year
OILPROD	=	Annual project level crude oil production

GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water production
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
OPSEC_W	=	Fixed annual operating cost for secondary well operations
SUMP	=	Cumulative patterns developed
AOAM	=	Fixed annual operating and maintenance costs
OAM	=	Variable annual operating and maintenance costs

Overhead Costs: : General and Administrative (G&A) costs on capitalized and expensed items, which consist of administration, accounting, contracting and legal fees/expenses for the project are calculated according to the following equations.

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}94)$$
$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}95)$$

Where,

ITECH	=	Technology case (base and advanced) number
GNA_EXP	=	The G&A rate applied to expensed items for the project
GNA_CAP	=	The G&A rate applied to capitalized items for the project
CHG_GNA_FAC	=	Technology case specific change in G&A rates

Timing

Overview of Timing Module

The timing routine determines which of the exploration and EOR/ASR projects are eligible for development in any particular year. Those which are eligible are subject to an economic analysis and passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects while the second is applied to EOR/ASR and developing natural gas projects.

Figure 2-9 provides the overall logic for the exploration component of the timing routine. For each project regional crude oil and natural gas prices are obtained. The project is then examined to see if it has previously been timed and developed. The timed projects are no longer available and thus not considered.

The model uses four resource access categories for the undiscovered projects:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use

- Standard leasing terms

Each project has been assigned to a resource access category. If the access category is not available in the year evaluated, the project fails the resource access check.

After the project is evaluated, the number of considered projects is increased. Figure 2-10 shows the timing logic applied to the EOR/ASR projects as well as the developing natural gas projects.

Before the economics are evaluated, the prices are set and the eligibility is determined. The following conditions must be met:

- Project has not been previously timed
- Project must be eligible for timing, re-passed the economic pre-screening routine
- Corresponding decline curve project must have been timed. This does not apply to the developing natural gas projects.

If the project meets all of these criteria, then eligibility for economic analysis is determined. For an EOR/ASR project to be considered for timing, it must be within a process specific EOR/ASR development window. These windows are listed in Table 2-4.

Table 2-4: EOR/ASR Eligibility Ranges

Process	Before Economic Limit	After Economic Limit
CO_2 Flooding	After 2009	10 Years
Steam Flooding	5 Years	10 Years
Polymer Flooding	5 Years	10 Years
Infill Drilling	After 2009	7 Years
Profile Modification	5 Years	7 Years
Horizontal Continuity	5 Years	7 Years
Horizontal Profile	5 Years	7 Years
Waterflood	4 Years	6 Years

The economic viability of the eligible projects is then determined. A different analytical approach is applied to CO_2 EOR and all other projects. For non-CO_2 EOR projects the project is screened for applicable technology levers and the economic analysis is conducted. CO_2 EOR projects are treated differently because of the different CO_2 costs associated with the different sources of industrial and natural CO_2.

The economics of these source specific projects are evaluated only if there is CO_2 available in the region from the source in that year.

For each available source the economics are calculated and the necessary variables are stored. These include the source of CO_2 and the projects ranking criterion.

Detailed description of timing module

Exploration projects: The first step in the timing module is to determine which reservoirs are eligible to be timed for conventional and continuous exploration. Constraints, resource access, and technology and economic levers are checked and the technology case is set, prior to evaluation.

Calculate economics for EOR/ASR and developing natural gas projects: This section determines whether an EOR/ASR or developing natural gas project is eligible for economic analysis and timing. The following resources are processes considered in this step.
EOR Processes:

- CO_2 Flooding
- Steam Flooding
- Polymer Flooding
- Profile Modification

ASR Processes:

- Water Flooding
- Infill Drilling
- Horizontal Continuity
- Horizontal Profile

Developing natural gas

- Tight Gas
- Shale Gas
- Coalbed Methane

A project is eligible for timing if the corresponding decline curve project has previously been timed and the year of evaluation is within the eligibility window for the process, as listed in table 2-4.

Project Ranking: Sorts exploration and EOR/ASR projects which are economic for timing. The subroutine matches the discovery order for undiscovered projects and sorts the other by ranking criterion. The criteria include:

- Net present value
- Investment efficiency
- Rate of return
- Cumulative discounted after tax cashflow

Selection and Timing: Times the exploration and EOR/ASR projects which are considered in that given year.

Project Selection

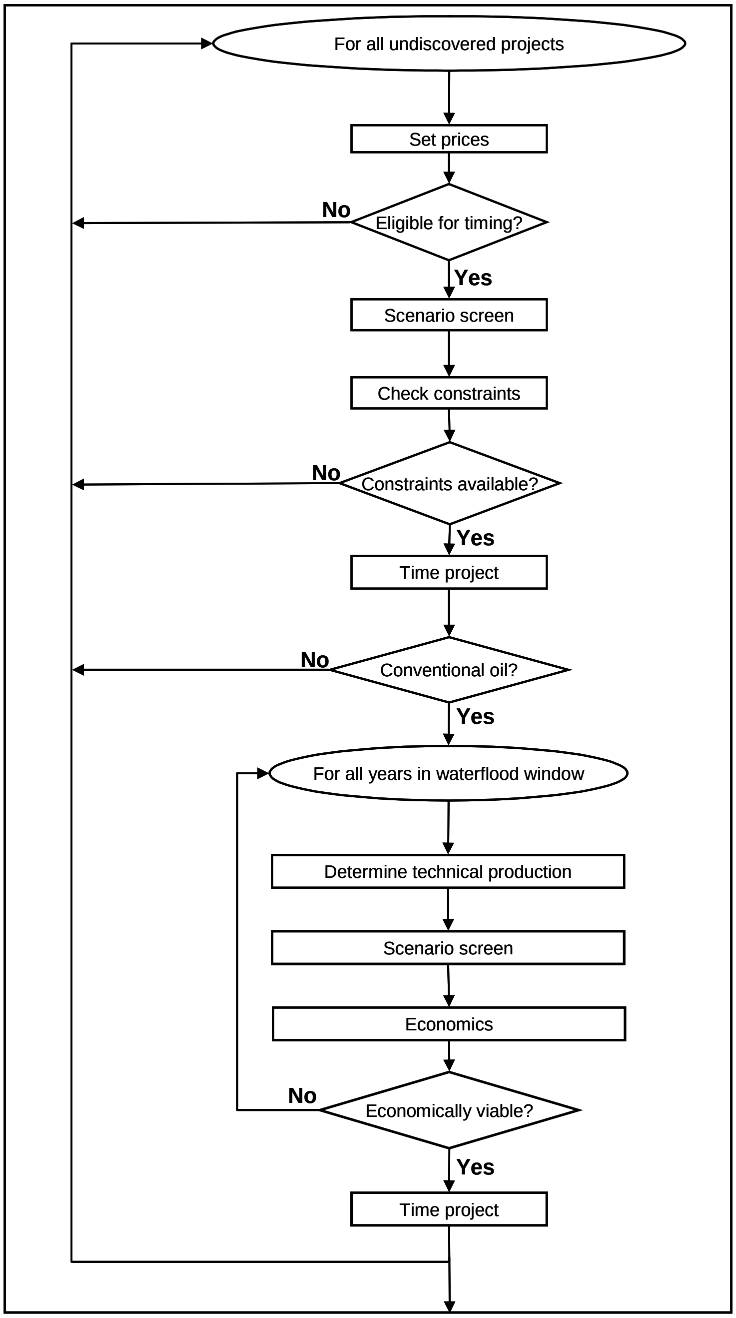
The project selection subroutine determines which exploration, EOR/ASR and developing natural gas projects will be developed in each year analyzed by the model. In addition, the following development decisions are made:

- Waterflood of conventional undiscovered crude oil projects
- Extension of CO_2 floods as the total CO_2 injected is increased from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV

Overview of Project Selection

The project selection subroutine evaluates undiscovered projects separate from other projects. The logic for the development of exploration projects is provided in figure 2-9.

Figure 2-9: Selecting Undiscovered Projects



As illustrated in the figure the prices are set for the project before its eligibility is checked. Eligibility has the following requirements:

- Project is economically viable
- Project is not previously timed and developed

The projects which are eligible are screened for applicable technologies which impact the drilling success rates. The development constraints required for the project are checked against those which are available in the region.

If sufficient development resources are available, the project is timed and developed. As part of this process the available development constraints are adjusted, the number of available accumulations is reduced and the results are aggregated. If no undiscovered accumulations remain, then the project is no longer eligible for timing. The projects which are eligible, economically viable, and undeveloped due to lack of development resources, will be considered again in future years. If the project is conventional crude oil it is possible to time a waterflood project.

The model evaluates the waterflood potential in a window centered upon the end of the economic life for the undiscovered project. For each year of that window, the technical production is determined for the waterflood project, applicable technology and economic levers are applied, and the economics are considered. If the waterflood project is economic, it will be timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine is applicable to EOR/ASR projects as well as the developing natural gas projects. The major steps applied to these projects are detailed in figures 2-10 and 2-11.

As seen in the flowchart, the prices are set for the project and the eligibility is checked. As with the undiscovered projects, the subroutine checks if the candidate project is both economically viable and eligible for timing. Afterwards, the project is screened for any applicable technology and economic levers.

If the project is eligible for CO_2 EOR, the economics are re-run for the specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules which govern the competition between projects and selection of projects, these rules are listed below:

- CO_2 EOR and infill drilling are available after 2008
- Profile modification becomes available after 2010
- The annual number of infill drilling and profile modification projects is limited
- Horizontal continuity can compete against any other process except steam flood
- Horizontal profile can compete against any other process except steam flood or profile modification
- Polymer flooding cannot compete against any other process

If the project meets the technology preferences, then it is timed and developed. This process is different for CO_2 EOR and all other processes.

Figure 2-10: Selecting EOR/ASR projects

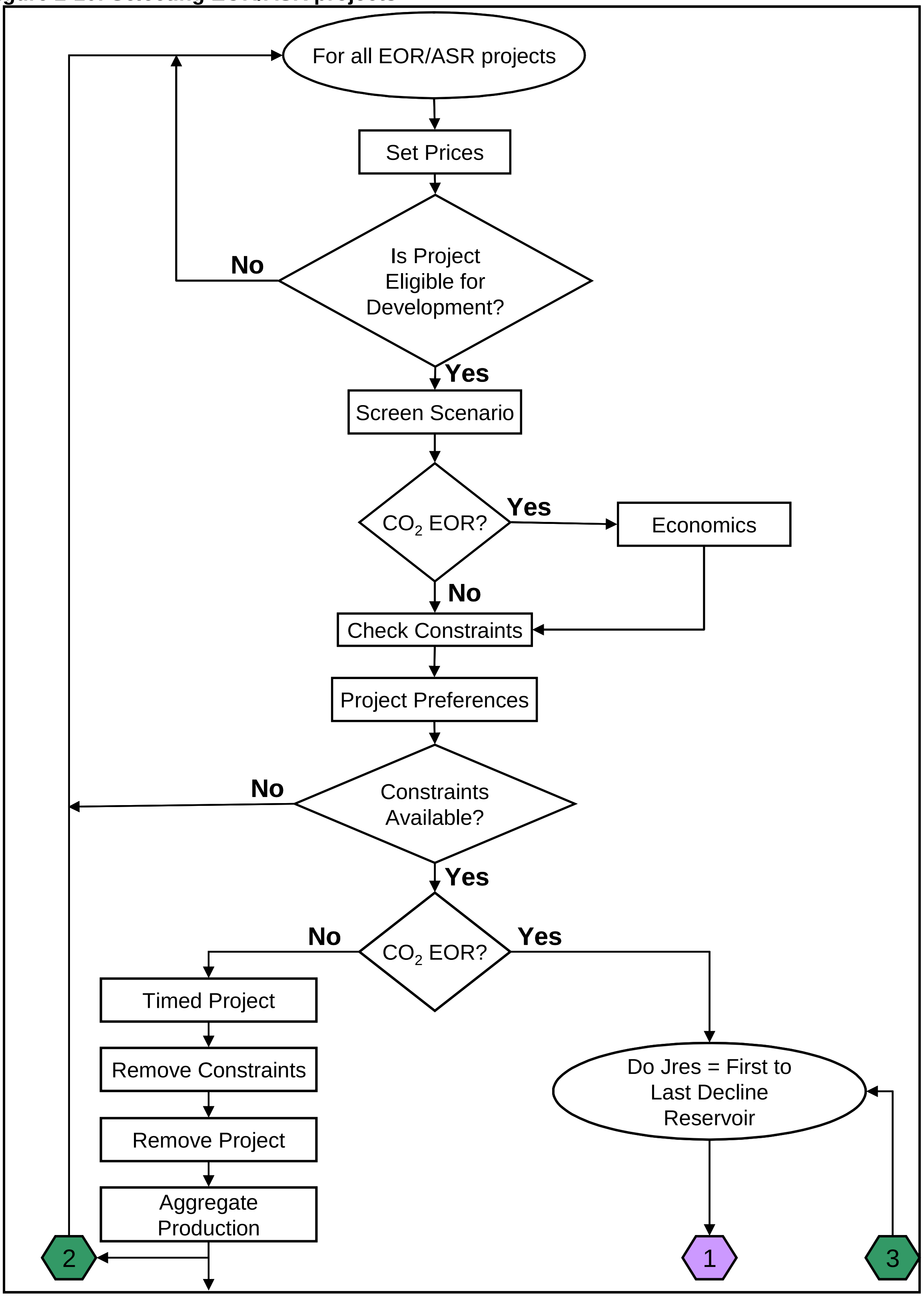
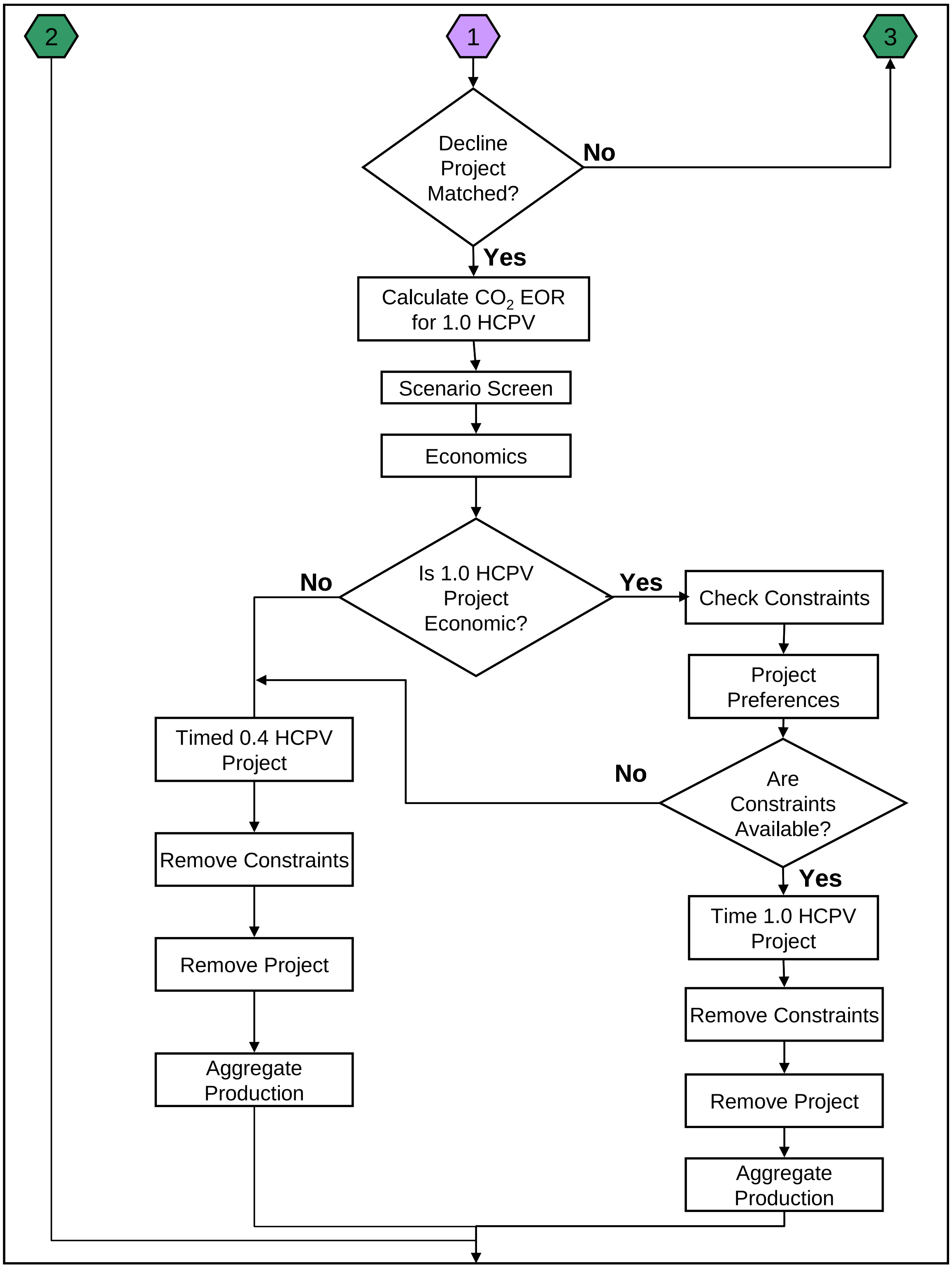


Figure 2-11: Selecting EOR/ASR projects, Continued



For non-CO_2 projects, the constraints are adjusted, the project is removed from the list of eligible projects, and the results are aggregated. It is assumed that most EOR/ASR processes are mutually exclusive and that a reservoir is limited to one process. There are a few exceptions:

- CO_2 EOR and infill drilling can be done in the same reservoir
- CO_2 EOR and horizontal continuity can be done in the same reservoir

For CO_2 EOR projects, a different methodology is used at this step; the decision to increase the total CO_2 injection from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV is made. The following steps, illustrated in figure 2-10 and continued in figure 2-11 are taken.

The CO_2 EOR project is matched to the corresponding decline curve project. Using the project-specific petro-physical properties, the technical production and injection requirements are determined for the 1.0 HCPV project. After applying any applicable technology and economic levers, the project economics are determined. If the 1.0 HCPV project is not economically viable, then the 0.4 HCPV project is timed. If the 1.0 HCPV project is viable, the constraints and project preferences are checked. Assuming that there are sufficient development resources, and competition allows for the development of the project, then the 1.0 HCPV project is timed. If sufficient resources for the 1.0 HCPV project are not available, then the 0.4 HCPV project is timed instead.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If the project is economic and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. Those projects, for which development resources are available, are developed.

Waterflood processing may be considered for undiscovered conventional crude oil projects. The waterflood project will be developed in the first year it is both eligible for implementation and the waterflood project is economically viable.

EOR/ASR Projects

When considering whether a project is eligible for EOR/ASR processing, the first step is to determine whether sufficient development resources are available in order to time an EOR/ASR project. In addition it makes the development decision, based upon the project economics and availability of development resources, to extend injection in CO_2 EOR projects from 0.4 HCPV to 1.0 HCPV.

If the 1.0 HCPV is economic but insufficient resources are available, the 0.4 HCPV project is selected instead. If the 1.0 HCPV project is uneconomic, the 0.4 HCPV project is selected.

Constraints

Resource development constraints are used during the selection of projects for development in order to mimic the infrastructure limitations of the oil and gas industry. As such, only the projects which do not exceed the constraints available will be developed by the model.

Types of constraints modeled

The development constraints represented in the model include drilling footage availability, rig depth rating, capital constraints, demand for natural gas, carbon dioxide volumes, and resource access.

In the remainder of this section, additional details will be provided for each of these constraints.

Drilling: Drilling constraints are bounding values used to determine the resource production in a given region. OLOGSS uses the following drilling categories:

- Developmental crude oil – applied to EOR/ASR projects
- Developmental natural gas – applied to developing natural gas projects
- Horizontal drilling – applied to horizontal wells
- Dual use – available for either crude oil or natural gas projects
- Conventional crude oil exploration – applied to undiscovered conventional crude oil projects
- Conventional natural gas exploration – applied to undiscovered conventional natural gas projects
- Continuous crude oil exploration – applied to undiscovered continuous crude oil projects
- Continuous natural gas exploration – applied to undiscovered continuous natural gas projects

Except for horizontal drilling, which is calculated as a fraction of the national developmental crude oil footage, all categories are calculated at the national level and apportioned to the regional level. Horizontal drilling is at the national level.

The following equations are used to calculate the national crude oil development drilling. The annual footage available is a function of lagged five year average crude oil prices and the total growth in drilling.

The total growth in drilling is calculated using the following algorithm.
For the first year:

$$\mathrm{TOT\_GROWTH} = 1.0 * \left(1.0 + \frac{\mathrm{DRILL\_OVER}}{100}\right) \tag{2-96}$$

For the remaining years: (2-97)

$$\mathrm{TOT\_GROWTH} = \left(\left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) - \left(\mathrm{TOT\_GROWTH} * \left(1.0 + \frac{\mathrm{RGR}}{100}\right)\right) * \left(\frac{\mathrm{RRR}}{100}\right)\right) * \left(1.0 * \frac{\mathrm{DRILL\_OVER}}{100}\right)$$

Where,

IYR	=	Year evaluated
MAX_YR	=	Maximum number of years
TOT_GROWTH	=	Annual growth change for drilling at the national level (fraction)

DRILL_OVER	=	Percent of drilling constraint available for footage over run
RGR	=	Annual rig development rate (percent)
RRR	=	Annual rig retirement rate (percent)

The national level crude oil and natural gas development drilling is calculated using the following equations.
The coefficients for the drilling footage equations were estimated according to equations 2.B-16 and 2.B-17 in Appendix 2.B.

$$NAT\_OIL_{IYR} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * OIL\_ADJ_{IYR} \tag{2-98}$$

$$NAT\_GAS_{IYR} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * GAS\_ADJ_{IYR} \tag{2-99}$$

Where,

IYR	=	Year evaluated
TOT_GROWTH	=	Final calculated annual growth change for drilling at the national level
NAT_OIL NAT_GAS	=	National development footage available (Thousand Feet)
OILA0,1 GASA0,1	=	Footage equation coefficients
OILPRICED GASPRICED	=	Annual prices used in drilling constraints, five year average
TOTMUL	=	Total drilling constraint multiplier
OIL_ADJ GAS_ADJ	=	Annual crude oil, natural gas developmental drilling availability factors

After the available drilling is calculated at the national level, regional allocations are used to allocate the drilling to each of the OLOGSS regions. The drilling which is not allocated, due to the "drill_trans" factor, is available in any region and represents the drilling which can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$REG\_OIL_{j,iyr} = NAT\_OIL_{IYR} * \left(\frac{PRO\_REGOIL_J}{100}\right) * \left(1.0 - \frac{DRILL\_TRANS}{100}\right) \tag{2-100}$$

Where,

J	=	Region number
IYR	=	Year
REG_OIL	=	Regional development oil footage (Thousand Feet) available in a specified region
NAT_OIL	=	National development oil footage (Thousand Feet). After allocation, the footage transferrable among regions.
PRO_REGOIL	=	Regional development oil footage allocation (percent)
DRILL_TRANS	=	Percent of footage which is transferable among regions

Footage Constraints: The model determines whether there is sufficient footage available to drill the complete project. The drilling constraint is applied to all projects. Footage requirements are calculated in two stages: vertical drilling and horizontal drilling. The first well for an exploration project is assumed to be a wildcat well and uses a different success rate than the other wells in the project. The vertical drilling is calculated using the following formula.

For non-exploration projects:

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEKD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech} \quad (2\text{-}101)$$

For exploration projects:

For the first year of the project (2-102)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUE_{itech})) * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (0.5 * ATOTCONV_{irs,itech}) + (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * (PATDEV_{irs,ii-itimeyr+1,itech} - 1 * ATOTPROD_{irs,itech} + ATOTINJ_{ir,itech} + 0.5 * ATOTCONV_{irs,itech})$$

For all other project years (2-103)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech})$$

Where:

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Thousand Feet)
DEPTH	=	Depth of formation (Feet)
SUC_RATEKD	=	Success rate for known development
SUC_RATEUE	=	Success rate for undiscovered exploration (wildcat)
SUC_RATEUD	=	Success rate for undiscovered development
PATDEV	=	Annual number of patterns developed for base and advanced technology
ATOTPROD	=	Number of new producers drilled per pattern
ATOTINJ	=	Number of new injectors drilled per patterns
ATOTCONV	=	Number of conversions from producing to injection wells per pattern

Add Laterals and Horizontal Wells: The lateral length and the horizontal well length are added to the footage required for drilling.

$$FOOTREQii = FOOTREQii + (ALATNUM_{irs,itech} * ALATLEN_{irs,itech} * (1.0 + SUC\_RATEKD_{itech}) * PATDEV_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}104)$$

Where,

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Feet)
ALATNUM	=	Number of laterals
ALATLEN	=	Length of laterals (Feet)
SUC_RATEKD	=	Success rate for known development
PATDEV	=	Annual number of patterns developed for base and advanced technology

After determining the footage requirements, the model calculates the footage which is available for the project. The available footage is specific to the resource, the process, and the constraint options which have been specified by the user. If the footage required to drill the project is greater than the footage available then the project is not feasible.

Rig depth rating: The rig depth rating is used to determine whether a rig is available which can drill to the depth required by the project. OLOGSS uses the nine rig depth categories provided in table 2-5.

Table 2-5 Rig Depth Categories

Depth Category	Minimum Depth (Ft)	Maximum Depth (Ft)
1	1	2,500
2	2,501	5,000
3	5,001	7,500
4	7,501	10,000
5	10,001	12,500
6	12,501	15,000
7	15,001	17,500
8	17,251	20,000
9	20,001	Deeper

The rig depth rating is applied at the national level. The available footage is calculated using the following equation.

$$RDR\_FOOTAGE_{j,\,iyr} = (NAT\_TOT_{iyr} + NAT\_EXP_{iyr} + NAT\_EXPG_{iyr}) * \frac{RDR_j}{100} \tag{2-106}$$

Where,

J	=	Rig depth rating category
IYR	=	Year
RDR_FOOTAGE	=	Footage available in this interval (K Ft)
NAT_TOT	=	Total national developmental (crude oil, natural gas, and horizontal) drilling footage available (Thousand feet)
NAT_EXPG	=	National gas exploration drilling constraint
NAT_EXP	=	Total national exploration drilling footage available (Thousand feet)

RDR = Percentage of rigs which can drill to that depth category

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on the amount of investments the oil and gas industry can make in a given year. The capital constraint is applied at the national level.

Natural Gas Demand: Demand for natural gas is calculated at the regional level by the NGTDM and supplied to OLOGSS.

Carbon Dioxide: For CO_2 miscible flooding, availability of CO_2 gas from natural and industrial sources is a limiting factor in developing the candidate projects. In the Permian Basin, where the majority of the current CO_2 projects are located, the CO_2 pipeline capacity is a major concern.

The CO_2 constraint in OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are ammonia plants, hydrogen plants, existing and planned ethanol plants, cement plants, refineries, fossil fuel power plants, and new IGCC plants.

Technology and market constraints prevent the total volumes of CO_2 from becoming immediately available. The development of the CO_2 market is divided into 3 periods:
1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no CO_2 is available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 first become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry which will adopt the technology has been reached. This provides an upper limit on the volume of CO_2 which will be available. The graph below provides the annual availability of CO_2 from ammonia plants. Availability curves were developed for each source of industrial, as well as natural CO_2.

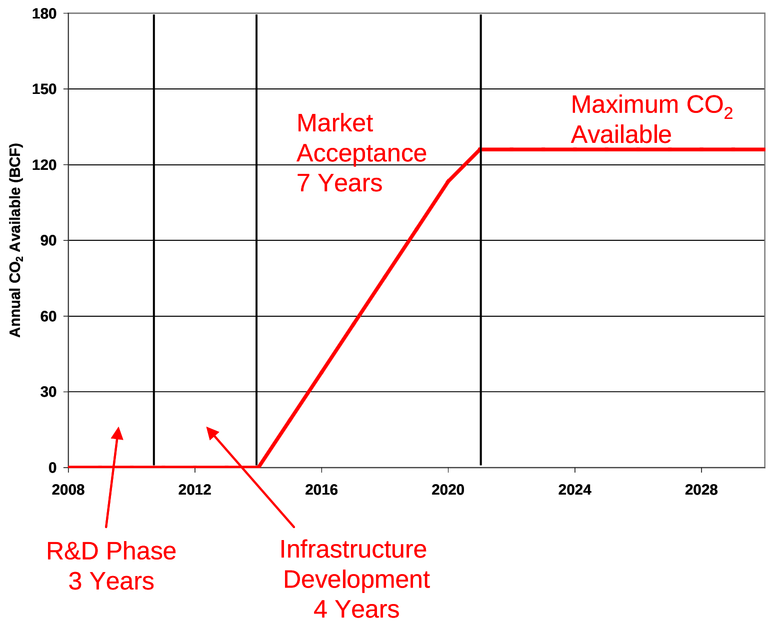
CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: The access to Federal lands is a constraint on the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was developed using the Department of Interior's Basin Inventories of Onshore Federal Land's Oil and Gas Resources.

Figure 2-12: CO2 Market Acceptance Curve



Technology

Research and development programs are designed to improve technology to increase the amount of resources recovered from crude oil and natural gas fields. Key areas of study are: increasing production, extending reserves, and reducing costs. To optimize the impact of R & D efforts, potential benefits of a new technology are weighed against the costs of research and development. OLOGSS has the capability to model the effects of R & D programs and other technology improvements as they impact the production and economics of a project. This is done in two steps: (1) modeling the implementation of the technology within the oil and gas industry and (2) modeling the costs and benefits for a project that applies this technology.

Impact of technology on economics and recovery

Figure 2-13 illustrates the effects of technology improvement on the production and project economics of a hypothetical well. The graphs plot the daily average production, projected by decline analysis, over the life of the project. Each graph represents a different scenario: (A) base case, (B) production improvement, and (C) economic improvement.

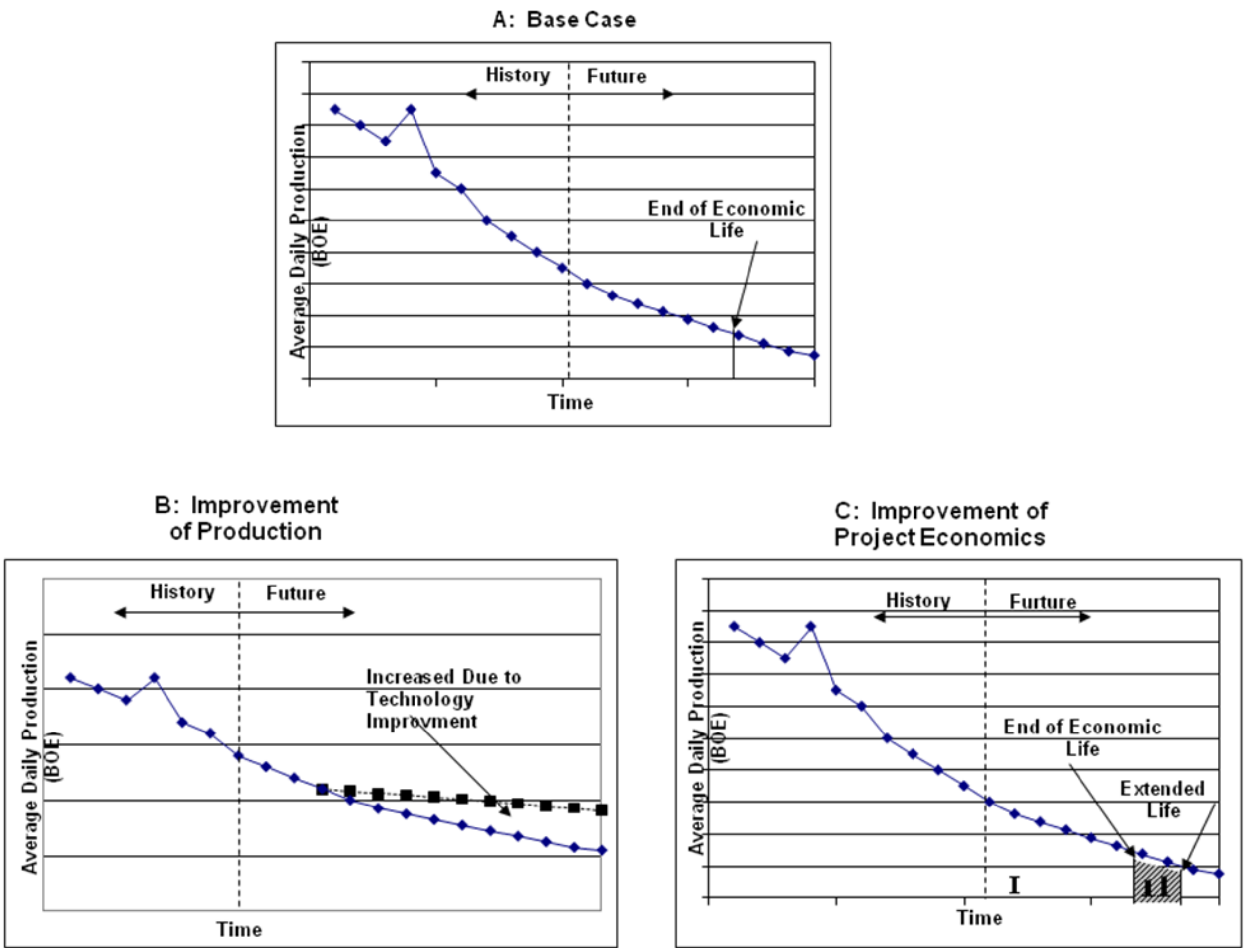
Graph A plots the production for the base case. In the base case, no new technology is applied to the project. The end of the project's economic life, the point at which potential revenues are less than costs of further production, is indicated. At that point, the project would be subject to reserves-growth processes or shut in.

Graph B plots the production for the base case and a production-increasing technology such as skin reduction. The reduction in skin, through well-bore fracturing or acidizing, increases the daily production flow rate. The increase in daily production rate is shown by the dotted line in graph B. The outcome of the production-increasing technology is reserves growth for the well.

The amount of reserves growth for the well is shown by the area between the two lines as illustrated in figure 2-13 graph B.

Another example of technology improvement is captured in graph C. In this case a technology is implemented that reduces the cost of operation and maintenance, thereby extending the reservoir life as shown in figure 2-13 graph C.

Figure 2-13: Impact of Economic and Technology Levers

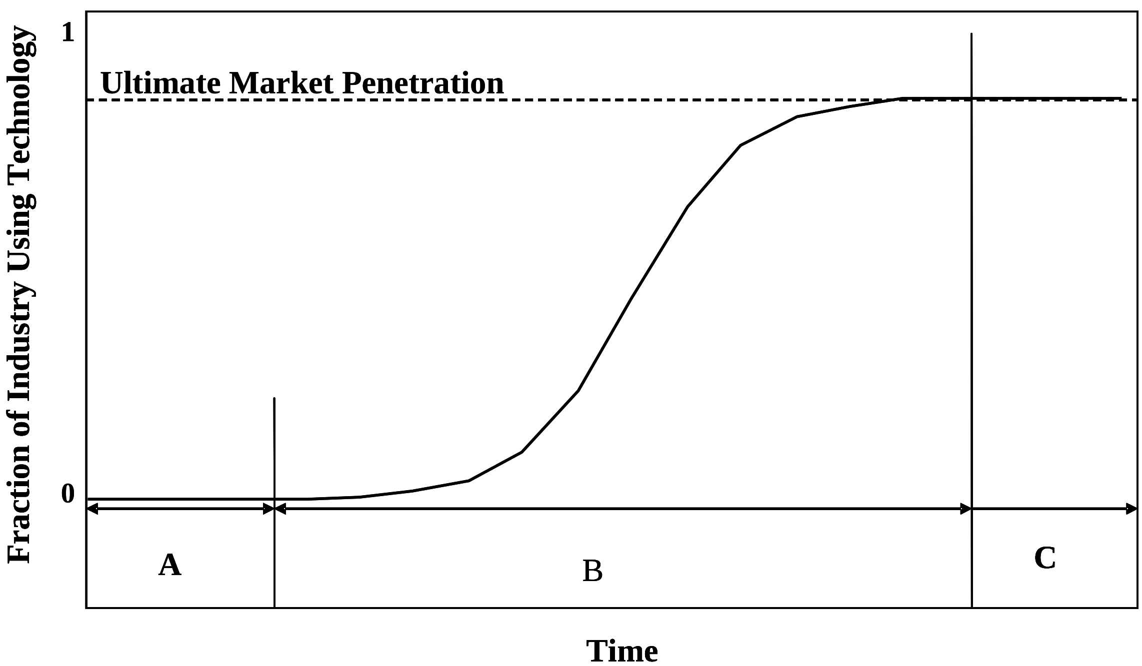


Technology improvements are modeled in OLOGSS using a variety of technology and economic levers. The technology levers, which impact production, are applied to the technical production of the project. The economic levers, which model improvement in project economics, are applied to cashflow calculations. Technology penetration curves are used to model the market penetration of each technology.

The technology-penetration curve is divided into three sections, each of which represents a phase of development. The first section is the research and development phase. In this phase the technology is developed and tested in the laboratory. During these years, the industry may be aware of the technology but has not begun implementation, and therefore does not see a benefit to production or economics. The second section corresponds to the commercialization phase. In the commercialization phase, the technology has successfully left the laboratory and is being adopted by the industry. The third section represents maximum market penetration. This is the ultimate extent to which the technology is adopted by the industry.

Figure 2-14 provides the graph of a generic technology-penetration curve. This graph plots the fraction of industry using the new technology (between 0 and 1) over time. During the research and development phase (A) the fraction of the industry using the technology is 0. This increases during commercialization phase (B) until it reaches the ultimate market penetration. In phase C, the period of maximum market acceptance, the percentage of industry using the technology remains constant.

Figure 2-14: Generic Technology Penetration Curve

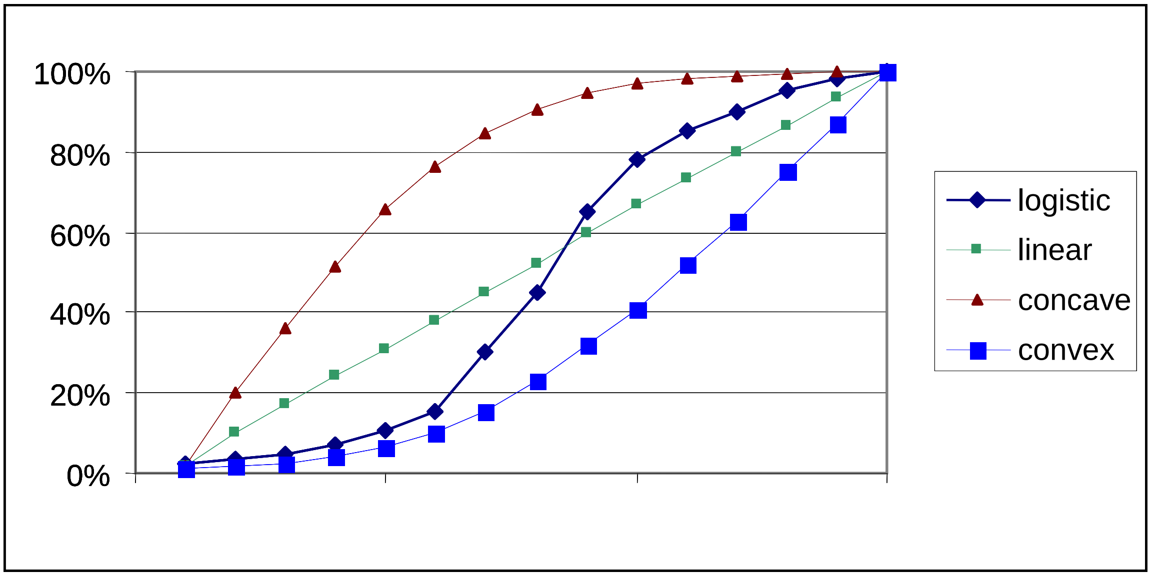


Technology modeling in OLOGSS

The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curves which represent the adoption of the technology: convex, concave, sigmoid/logistic or linear, as shown in figure 2-15. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The implementation probability does not reflect resource access, development constraints, or economic factors.

Figure 2-15: Potential Market Penetration Profiles



The three phases of the technology penetration curve are modeled using three sets of equations. The first set of equations models the research and development phase, the second set models the commercialization phase, and the third set models the maximum market penetration phase.

In summary, technology penetration curves are defined using the following variables:

- Number of years required to develop a technology = Y_d
- First year of commercialization = Y_c
- Number of years to fully penetrate the market = Y_a
- Ultimate market penetration (%) = UP
- Probability of success = P_s
- Probability of implementation = P_i
- Percent of industry implementing the technology (fraction) in year x = Imp_x

Research and Development Phase:
During the research and development phase, the percentage of industry implementing the new technology for a given year is zero.

This equation is used for all values of *market_penetration_profile.*

Commercialization Phase:
The commercialization phase covers the years from the beginning of commercialization through the number of years to develop the technology. The equations used to model this phase depend upon the value of *market_penetration_profile.*

If the *market_penetration_profile* is assumed to be *convex*, then

Step 1: Calculate raw implementation percentage:

$$Imp_{xr} = -0.9 * 0.4^{[(x - Ys) / Ya]} \tag{2-105}$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(-0.6523) - Imp_x]}{[(-0.6523) - (-0.036)]} \tag{2-106}$$

If the *market_penetration_profile* is assumed to be *concave*, then

Step 1: Calculate raw implementation percentage:

$$Imp_x = 0.9 * 0.04^{[1 - \{(x + 1 - Ys)/ Ya\}]} \tag{2-107}$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(0.04) - Imp_{xr}]}{[(0.04) - (0.74678)]} \tag{2-108}$$

If the *market_penetration_profile* is assumed to be *sigmoid*, then

Step 1: Determine midpoint of the sigmoid curve = int $\left(\frac{Y_a}{2}\right)$

Where int$\left(\frac{Y_a}{2}\right) = \left(\frac{Y_a}{2}\right)$ rounded to the nearest integer

Step 2: Assign value of 0 to midpoint year (of years to be commercialized), positive increment values to the years above the midpoint year, and negative increment values to the years below the midpoint value.

Step 3: Calculate raw implementation percentage:

$$Imp_x = \frac{e^{value_x}}{1 + e^{value_x}} \tag{2-109}$$

No normalizing of Imp_x is required for the sigmoid profile.

If the *market_penetration_profile* is assumed to be *linear*, then

Step 1: Calculate the raw implementation percentage:

$$\text{Imp}_x = \left[\frac{P_s * P_i * UP}{Y_a + 1}\right] * x_i \qquad (2\text{-}110)$$

No normalizing of Imp_x is required for the linear profile.

Note that the maximum technology penetration is 1.

Ultimate Market Penetration Phase:
For each of the curves generated, the ultimate technology penetration applied per year will be calculated using:

$$\text{Imp}_{final} = \text{Imp}_x * P_s * P_i \qquad (2\text{-}111)$$

Note that Imp_{final} is not to exceed Ultimate Market Penetration (“UP”)

By using these three sets of equations, the industry-wide implementation of a technology improvement can be mapped using a technology-penetration curve.

Levers included in model

Project Level Technology Impact: Adopting a new technology can impact two aspects of a project. It improves the production and/or improves the economics. Technology and economic levers are variables in OLOGSS. The values for these levers are set by the user.

There are two ways in which economic levers are applied to the cashflow calculations: the cost to apply the technology and cost reductions. The cost to apply is the incremental cost to apply the technology. The cost reduction is the savings associated with using the new technology. There are two options for the application of the “cost to apply” levers. They can be applied at the well and/or project level. This incorporates the distinction between technologies which are applied at the well level – modeling while drilling; versus reservoir characterization and simulation - which affects the entire project. Each type of cost is modeled using economic levers. The cost reduction costs model the savings brought about through technology improvement. By using both types of levers, the synergy between additional costs and offsetting cost reductions can be captured.

The technology will be implemented by the model only if the cost to apply the technology is less than the increased revenue generated by improved production and by cost reductions.

Resource and Filter Levers: Two other types of levers are incorporated into OLOGSS: resource-access levers and technology levers. Resource-access levers allow the user to model changes in resource-access policy. For example, the user can specify that the federal lands in the Santa Maria Basin, which are currently inaccessible due to statutory or executive orders, will be available for exploration in 2015. A series of filter levers are also incorporated in the model.

These are used to specifically locate the impact of technology improvement. For example, a technology can be applied only to CO_2 flooding projects in the Rocky Mountain region which are between 5,000 and 7,000 feet deep.

Appendix 2.A: Onshore Lower 48 Data Inventory

Variable Name	Variable Type	Description	Unit
AAPI	Input	API gravity	
AARP	Input	CO_2 source acceptance rate	
ABO	Variable	Current formation volume factor	Bbl/stb
ABOI	Input	Initial formation volume factor	Bbl/stb
ABTU	Variable	BTU content	Btu/Cf
ACER	Input	ACE rate	Percent
ACHGASPROD	Input	Cumulative historical natural gas production	MMcf
ACHOILPROD	Input	Cumulative historical crude oil production	MBbl
ACO2CONT	Input	CO_2 impurity content	%
ADEPTH	Input	Depth	Feet
ADGGLA	Variable	Depletable items in the year (G & G and lease acquisition cost)	K$
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	K$
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/Bbl
ADVANCED	Variable	Patterns to be developed using advanced technology	Fraction
AECON_LIFE	Variable	Economic life of the project	Years
AFLP	Input	Portion of reservoir on federal lands	Fraction
AGAS_GRAV	Input	Natural gas gravity	
AGOR	Input	Gas/oil ratio	Mcf/bbl
AH2SCONT	Input	H_2S impurity content	%
AHCPV	Variable	Hydro Carbon Pore Volume	0.4 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/Cf
AINJINJ	Input	Annual injectant injected	MBbl, Mcf, MLbs
AINJRECY	Variable	Annual injectant recycled	MBbl, Mcf
AIRSVGAS	Variable	End of year inferred natural gas reserves	MMcf
AIRSVOIL	Variable	End of year inferred crude oil reserves	MBbl
ALATLEN	Input	Lateral length	Feet
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf

ALYROIL	Input	Last year of historical crude oil production	MBbl
AMINT	Variable	Alternative minimum income tax	K$
AMOR	Variable	Intangible investment depreciation amount	K$
AMOR_BASE	Variable	Amortization base	K$
AMORSCHL	Input	Annual fraction amortized	Fraction
AMT	Input	Alternative minimum tax	K$
AMTRATE	Input	Alternative minimum tax rate	K$
AN2CONT	Input	N_2 impurity content	%
ANGL	Input	NGL	bbl/MMcf
ANUMACC	Input	Number of accumulations	
ANWELLGAS	Input	Number of natural gas wells	
ANWELLINJ	Input	Number of injection wells	
ANWELLOIL	Input	Number of crude oil wells	
AOAM	Variable	Annual fixed O & M cost	K$
AOGIP	Variable	Original Gas in Place	Bcf
AOILVIS	Input	Crude Oil viscosity	CP
AOOIP	Variable	Original Oil In Place	MBbl
AORGOOIP	Input	Original OOIP	MBbl
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	Feet
APD	Variable	Annual percent depletion	K$
APERM	Input	Permeability	MD
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	PSIA
APRODCO2	Input	Annual CO_2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual NGL production	MBbl
APRODOIL	Input	Annual crude oil production	MBbl
APRODWAT	Input	Annual water production	MBbl
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource Access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARESVGAS	Variable	End of year proven natural gas reserves	MMcf
ARESVOIL	Variable	End of year proven crude oil reserves	MBbl
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir Size Class	
ASGI	Variable	Gas saturation	Percent
ASOC	Input	Current oil saturation	Percent
ASOI	Input	Initial oil saturation	Percent

ASOR	Input	Residual oil saturation	Percent
ASR_ED	Input	Number of years after economic life of ASR	
ASR_ST	Input	Number of years before economic life of ASR	
ASULFOIL	Input	Sulfur content of crude oil	%
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cashflow	K$
ATEMP	Variable	Reservoir temperature	F°
ATOTACRES	Input	Total area	Acres
ATOTCONV	Input	Number of conversions from producing wells to injecting wells per pattern	
ATOTINJ	Input	Number of new injectors drilled per pattern	
ATOTPAT	Input	Total number of patterns	
ATOTPROD	Input	Number of new producers drilled per pattern	
ATOTPS	Input	Number of primary wells converted to secondary wells per pattern	
AVDP	Input	Dykstra Parsons coefficient	
AWATINJ	Input	Annual water injected	MBbl
AWOR	Input	Water/oil ratio	Bbl/Bbl
BAS_PLAY	Input	Basin number	
BASEGAS	Input	Base natural gas price used for normalization of capital and operating costs	$/Mcf
BASEOIL	Input	Base crude oil price used for normalization of capital and operating costs	K$
BSE_AVAILCO2	Variable	Base annual volume of CO_2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	K$
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cashflow	K$
CHG_ANNSEC_FAC	Input	Change in annual secondary operating cost	Fraction
CHG_CHMPNT_FAC	Input	Change in chemical handling plant cost	Fraction
CHG_CMP_FAC	Input	Change in compression cost	Fraction
CHG_CO2PNT_FAC	Input	Change in CO_2 injection/recycling plant cost	Fraction
CHG_COMP_FAC	Input	Change in completion cost	Fraction
CHG_DRL_FAC	Input	Change in drilling cost	Fraction
CHG_FAC_FAC	Input	Change in facilities cost	Fraction

CHG_FACUPG_FAC	Input	Change in facilities upgrade cost	Fraction
CHG_FOAM_FAC	Input	Change in fixed annual O & M cost	Fraction
CHG_GNA_FAC	Input	Change in G & A cost	Fraction
CHG_INJC_FAC	Input	Change in injection cost	Fraction
CHG_INJCONV_FAC	Input	Change in injector conversion cost	Fraction
CHG_INJT_FAC	Input	Change in injectant cost	Fraction
CHG_LFT_FAC	Input	Change in lifting cost	Fraction
CHG_OGAS_FAC	Input	Change in natural gas O & M cost	K$
CHG_OINJ_FAC	Input	Change in injection O & M cost	K$
CHG_OOIL_FAC	Input	Change in oil O & M cost	K$
CHG_OWAT_FAC	Input	Change in water O & M cost	K$
CHG_PLYPNT_FAC	Input	Change in polymer handling plant cost	Fraction
CHG_PRDWAT_FAC	Input	Change in produced water handling plant cost	Fraction
CHG_SECWRK_FAC	Input	Change in secondary workover cost	Fraction
CHG_SECCONV_FAC	Input	Change in secondary conversion cost	Fraction
CHG_STM_FAC	Input	Change in stimulation cost	Fraction
CHG_STMGEN_FAC	Input	Change in steam generation and distribution cost	Fraction
CHG_VOAM_FAC	Input	Change in variable O & M cost	Fraction
.CHG_WRK_FAC	Input	Change in workover cost	Fraction
CHM_F	Variable	Cost for a chemical handling plant	K$
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	K$
CO2_F	Variable	Cost for a CO_2 recycling/injection plant	K$
CO2_RAT_ FAC	Input	CO_2 injection factor	
CO2AVAIL	Variable	Total CO_2 available in a region across all sources	Bcf/Yr
CO2BASE	Input	Total Volume of CO_2 Available	Bcf/Yr
CO2COST	Variable	Final cost for CO_2	$/Mcf

CO2B	Input	Constant and coefficient for natural CO_2 cost equation	
CO2K	Input	Constant and coefficient for natural CO_2 cost equation	
CO2MUL	Input	CO_2 availability constraint multiplier	
CO2OAM	Variable	CO_2 variable O & M cost	K$
CO2OM_20	Input	The O & M cost for CO_2 injection < 20 MMcf	K$
CO2OM20	Input	The O & M cost for CO_2 injection > 20 MMcf	K$
CO2PR	Input	State/regional multipliers for natural CO_2 cost	
CO2PRICE	Input	CO_2 price	$/Mcf
CO2RK, CO2RB	Input	CO_2 recycling plant cost	K$
CO2ST	Input	State code for natural CO_2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	K$
COMP_OAM	Variable	Compressor O & M cost	K$
COMP_VC	Input	Compressor O & M costs	K$
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	K$
COMYEAR_FAC	Input	Number of years of technology commercialization for the penetration curve	Years
CONTIN_ FAC	Input	Continuity increase factor	
COST_BHP	Input	Compressor Cost	$/Bhp
COTYPE	Variable	CO_2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
CPI_2005	Variable	CPI conversion for 2005$	
CPI_AVG	Input	Average CPI from 1990 to 2010	
CPI_FACTOR	Input	CPI factor from 1990 to 2010	
CPI_YEAR	Input	Year for CPI index	
CREDAMT	Input	Flag that allows AMT to be credited in future years	
CREGPR	Input	The CO_2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well level cost to apply secondary producer technology	K$
CST_ANNSEC_CSTP	Variable	Project level cost to apply secondary producer technology	K$

CST_CMP_CSTP	Variable	Project level cost to apply compression technology	K$
CST_CMP_FAC	Input	Well level cost to apply compression technology	K$
CST_COMP_ FAC	Input	Well level cost to apply completion technology	K$
CST_COMP_CSTP	Variable	Project level cost to apply completion technology	K$
CST_DRL_ FAC	Input	Well level cost to apply drilling technology	K$
CST_DRL_CSTP	Variable	Project level cost to apply drilling technology	K$
CST_FAC_ FAC	Input	Well level cost to apply facilities technology	K$
CST_FAC_CSTP	Variable	Project level cost to apply facilities technology	K$
CST_FACUPG_ FAC	Input	Well level cost to apply facilities upgrade technology	K$
CST_FACUPG_CSTP	Variable	Project level cost to apply facilities upgrade technology	K$
CST_FOAM_ FAC	Input	Well level cost to apply fixed annual O & M technology	K$
CST_FOAM_CSTP	Variable	Project level cost to apply fixed annual O & M technology	K$
CST_GNA_ FAC	Input	Well level cost to apply G & A technology	K$
CST_GNA_CSTP	Variable	Project level cost to apply G & A technology	K$
CST_INJC_ FAC	Input	Well level cost to apply injection technology	K$
CST_INJC_CSTP	Variable	Project level cost to apply injection technology	K$
CST_INJCONV_ FAC	Input	Well level cost to apply injector conversion technology	K$
CST_INJCONV_CSTP	Variable	Project level cost to apply injector conversion technology	K$
CST_LFT_ FAC	Input	Well level cost to apply lifting technology	K$
CST_LFT_CSTP	Variable	Project level cost to apply lifting technology	K$
CST_SECCONV_ FAC	Input	Well level cost to apply secondary conversion technology	K$

CST_SECCONV_CSTP	Variable	Project level cost to apply secondary conversion technology	K$
CST_SECWRK_ FAC	Input	Well level cost to apply secondary workover technology	K$
CST_SECWRK_CSTP	Variable	Project level cost to apply secondary workover technology	K$
CST_STM_ FAC	Input	Well level cost to apply stimulation technology	K$
CST_STM_CSTP	Variable	Project level cost to apply stimulation technology	K$
CST_VOAM_ FAC	Input	Well level cost to apply variable annual O & M technology	K$
CST_VOAM_CSTP	Variable	Project level cost to apply variable annual O & M technology	K$
CST_WRK_ FAC	Input	Well level cost to apply workover technology	K$
CST_WRK_CSTP	Variable	Project level cost to apply workover technology	K$
CSTP_ANNSEC_ FAC	Input	Project level cost to apply secondary producer technology	K$
CSTP_CMP_ FAC	Input	Project level cost to apply compression technology	K$
CSTP_COMP_ FAC	Input	Project level cost to apply completion technology	K$
CSTP_DRL_ FAC	Input	Project level cost to apply drilling technology	K$
CSTP_FAC_ FAC	Input	Project level cost to apply facilities technology	K$
CSTP_FACUPG_ FAC	Input	Project level cost to apply facilities upgrade technology	K$
CSTP_FOAM_ FAC	Input	Project level cost to apply fixed annual O & M technology	K$
CSTP_GNA_ FAC	Input	Project level cost to apply G & A technology	K$
CSTP_INJC_ FAC	Input	Project level cost to apply injection technology	K$
CSTP_INJCONV_ FAC	Input	Project level cost to apply injector conversion technology	K$
CSTP_LFT_ FAC	Input	Project level cost to apply lifting technology	K$

CSTP_SECCONV_ FAC	Input	Project level cost to apply secondary conversion technology	K$
CSTP_SECWRK_ FAC	Input	Project level cost to apply secondary workover technology	K$
CSTP_STM_ FAC	Input	Project level cost to apply stimulation technology	K$
CSTP_VOAM_ FAC	Input	Project level cost to apply variable annual O & M technology	K$
CSTP_WRK_ FAC	Input	Project level cost to apply workover technology	K$
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/Bbl
DATCF	Variable	Discounted cashflow after taxes	K$
DEP_CRD	Variable	Depletion credit	K$
DEPLET	Variable	Depletion allowance	K$
DEPR	Variable	Depreciation amount	K$
DEPR_OVR	Input	Annual fraction to depreciate	
DEPR_PROC	Input	Process number for override schedule	
DEPR_YR	Input	Number of years for override schedule	
DEPRSCHL	Input	Annual Fraction Depreciated	Fraction
DEPR_SCH	Variable	Process specific depreciation schedule	Years
DGGLA	Variable	Depletion base (G & G and lease acquisition cost)	K$
DISC_DRL	Variable	Discounted drilling cost	K$
DISC_FED	Variable	Discounted federal tax payments	K$
DISC_GAS	Variable	Discounted revenue from natural gas sales	K$
DISC_INV	Variable	Discounted investment rate	K$
DISC_NDRL	Variable	Discounted project facilities costs	K$
DISC_OAM	Variable	Discounted O & M cost	K$
DISC_OIL	Variable	Discounted revenue from crude oil sales	K$
DISC_ROY	Variable	Discounted royalty	K$
DISC_ST	Variable	Discounted state tax rate	K$
DISCLAG	Input	Number of years between discovery and first production	
DISCOUNT_RT	Input	Process discount rates	Percent

DRCAP_D	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
DRCAP_G	Variable	Regional natural gas well drilling footage constraints	Ft
DRCAP_O	Variable	Regional crude oil well drilling footage constraints	Ft
DRILL_FAC	Input	Drilling rate factor	
DRILL_OVER	Input	Drilling constraints available for footage over run	%
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	%
DRILL_TRANS	Input	Drilling constraints transfer between regions	%
DRILLCST	Variable	Drill cost by project	K$
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	K$
DRY_CST	Variable	Dryhole drilling cost	K$
DRY_DWCA	Estimated	Dryhole well cost	K$
DRY_DWCB	Estimated	Dryhole well cost	K$
DRY_DWCC	Estimated	Dryhole well cost	K$
DRY_DWCD	Input	Maximum depth range for dry well drilling cost equations	Ft
DRY_DWCK	Estimated	Constant for dryhole drilling cost equation	
DRY_DWCM	Input	Minimum depth range for dry well drilling equations	Ft
DRY_W	Variable	Cost to drill a dry well	K$
DRYCST	Variable	Dryhole cost by project	K$
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	Wells
DWC_W	Variable	Cost to drill and complete a crude oil well	K$
EADGGLA	Variable	G&G and lease acquisition cost depletion	K$
EADJGROSS	Variable	Adjusted revenue	K$
EAMINT	Variable	Alternative minimum tax	K$
EAMOR	Variable	Amortization	K$
EAOAM	Variable	Fixed annual operating cost	K$
EATCF	Variable	After tax cash flow	K$
ECAP_BASE	Variable	Depreciable/capitalized base	K$

ECATCF	Variable	Cumulative discounted after tax cashflow	K$
ECO2CODE	Variable	CO_2 source code	
ECO2COST	Variable	CO_2 cost	K$
ECO2INJ	Variable	Economic CO_2 injection	Bcf/Yr
ECO2LIM	Variable	Source specific project life for CO_2 EOR projects	
ECO2POL	Variable	Injected CO_2	MMcf
ECO2RANKVAL	Variable	Source specific ranking value for CO_2 EOR projects	
ECO2RCY	Variable	CO_2 recycled	Bcf/Yr
ECOMP	Variable	Compressor tangible capital	K$
EDATCF	Variable	Discounted after tax cashflow	K$
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	K$
EDEPGGLA	Variable	Depletable G & G/lease cost	K$
EDEPLET	Variable	Depletion	K$
EDEPR	Variable	Depreciation	K$
EDGGLA	Variable	Depletion base	K$
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	K$
EEGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EEORTCA	Variable	Tax credit addback	K$
EEXIST_ECAP	Variable	Environmental existing capital	K$
EEXIST_EOAM	Variable	Environmental existing O & M costs	K$
EFEDCR	Variable	Federal tax credits	K$
EFEDROY	Variable	Federal royalty	K$
EFEDTAX	Variable	Federal tax	K$
EFOAM	Variable	CO_2 FOAM cost	K$
EGACAP	Variable	G & A capitalized	K$
EGAEXP	Variable	G & A expensed	K$
EGASPRICE2	Variable	Natural gas price used in the economics	K$
EGG	Variable	Expensed G & G cost	K$
EGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EGGLAADD	Variable	G & G/lease addback	K$
EGRAVADJ	Variable	Gravity adjustment	K$
EGREMRES	Variable	Remaining proven natural gas reserves	Bcf
EGROSSREV	Variable	Gross revenues	K$
EIA	Variable	Environmental intangible addback	K$

EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EIGREMRES	Variable	Remaining inferred natural gas reserves	Bcf
EII	Variable	Intangible investment	K$
EIIDRL	Variable	Intangible investment drilling	K$
EINJCOST	Variable	CO_2/Polymer cost	K$
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	K$
EINTCAP	Variable	Tangible investment drilling	K$
EINVEFF	Variable	Investment efficiency	
EIREMRES	Variable	Remaining inferred crude oil reserves	MMBbl
EITC	Input	Environmental intangible tax credit	K$
EITCAB	Input	Environmental intangible tax credit rate addback	%
EITCR	Input	Environmental intangible tax credit rate	K$
ELA	Variable	Lease and acquisition cost	K$
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	MBbl
ENETREV	Variable	Net revenues	K$
ENEW_ECAP	Variable	Environmental new capital	K$
ENEW_EOAM	Variable	Environmental new O & M costs	K$
ENIAT	Variable	Net income after taxes	K$
ENIBT	Variable	Net income before taxes	K$
ENPV	Variable	Net present value	K$
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs?	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	K$

EOCA	Variable	Environmental operating cost addback	K$
EOCTC	Input	Environmental operating cost tax credit	K$
EOCTCAB	Input	Environmental operating cost tax credit rate addback	%
EOCTCR	Input	Environmental operating cost tax credit rate	K$
EOILPRICE2	Variable	Crude oil price used in the economics	K$
EORTC	Input	EOR tax credit	K$
EORTCA	Variable	EOR tax credit addback	K$
EORTCAB	Input	EOR tax credit rate addback	%
EORTCP	Input	EOR tax credit phase out crude oil price	K$
EORTCR	Input	EOR tax credit rate	K$
EORTCRP	Input	EOR tax credit applied by year	%
EOTC	Variable	Other tangible capital	K$
EPROC_OAM	Variable	Natural gas processing cost	K$
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	MBbl
EPRODWAT	Variable	Economic water production	MBbl
EPRODWELL	Variable	Active producing wells per year	
EREMRES	Variable	Remaining proven crude oil reserves	MMBbl
EROR	Variable	Rate of return	
EROY	Variable	Royalty	K$
ESEV	Variable	Severance tax	K$
ESHUTIN	Variable	New shut in wells drilled per year	
ESTIM	Variable	Stimulation cost	K$
ESTTAX	Variable	State tax	K$
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ MBbl/ MLbs
ETAXINC	Variable	Net income before taxes	K$
ETCADD	Variable	Tax credit addbacks taken from NIAT	K$
ETCI	Variable	Federal tax credit	K$
ETCIADJ	Variable	Adjustment for federal tax credit	K$

ETI	Variable	Tangible investments	K$
ETOC	Variable	Total operating cost	K$
ETORECY	Variable	CO_2/Surf/Steam recycling volume	Bcf/MBbl/Yr
ETORECY_CST	Variable	CO_2/Surf/Steam recycling cost	Bcf/MBbl/Yr
ETTC	Input	Environmental tangible tax credit	K$
ETTCAB	Input	Environmental tangible tax credit rate addback	%
ETTCR	Input	Environmental tangible tax credit rate	K$
EWATINJ	Variable	Economic water injected	MBbl
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	K$
EXIST_EOAM	Variable	Existing environmental O & M cost	K$
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling which is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling which is made available	Fraction
EXPA0	Estimated	Crude oil exploration well footage A0	
EXPA1	Estimated	Crude oil exploration well footage A1	
EXPAG0	Input	Natural gas exploration well footage A0	
EXPAG1	Input	Natural gas exploration well footage A1	
EXPATN	Variable	Number of active patterns	
EXPCDRCAP	Variable	Regional conventional exploratory drilling footage constraints	Ft
EXPCDRCAPG	Variable	Regional conventional natural gas exploration drilling footage constraint	Ft
EXPGG	Variable	Expensed G & G cost	K$
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	%
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	%

EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	K$
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	
EXPLSORTIRES	Variable	Sort pointer for exploration	
EXPMUL	Input	Exploration constraint multiplier	
EXPRDL48	Variable	Expected Production	Oil-MMB Gas-BCF
EXPUDRCAP	Variable	Regional continuous exploratory drilling footage constraints	Ft
EXPUDRCAPG	Variable	Regional continuous natural gas exploratory drilling footage constraints	Ft
FAC_W	Variable	Facilities upgrade cost	K$
FACCOST	Variable	Facilities cost	K$
FACGA	Estimated	Natural gas facilities costs	
FACGB	Estimated	Natural gas facilities costs	
FACGC	Estimated	Natural gas facilities costs	
FACGD	Input	Maximum depth range for natural gas facilities costs	Ft
FACGK	Estimated	Constant for natural gas facilities costs	
FACGM	Input	Minimum depth range for natural gas facilities costs	Ft
FACUPA	Estimated	Facilities upgrade cost	
FACUPB	Estimated	Facilities upgrade cost	
FACUPC	Estimated	Facilities upgrade cost	
FACUPD	Input	Maximum depth range for facilities upgrade cost	Ft
FACUPK	Estimated	Constant for facilities upgrade costs	
FACUPM	Input	Minimum depth range for facilities upgrade cost	Ft
FCO2	Variable	Cost multiplier for natural CO_2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	K$
FEDTAX_CR	Variable	Federal tax credits	K$
FIRST_ASR	Variable	First year a decline reservoir will be considered for ASR	
FIRST_DEC	Variable	First year a decline reservoir will be considered for EOR	

FIRSTCOM_FAC	Input	First year of commercialization for technology on the penetration curve	
FIT	Variable	Federal income tax	K$
FOAM	Variable	CO_2 fixed O & M cost	K$
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	K$
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	K$
FOAMG_W	Variable	Fixed operating cost for natural gas wells	K$
FGASPRICE	Input	Fixed natural gas price	$/MCF
FOILPRICE	Input	Fixed crude oil price	$/BBL
FPLY	Variable	Cost multiplier for polymer	
FPRICE	Input	Selection to use fixed prices	
FR1L48	Variable	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well
FR2L48	Variable	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well
FR3L48	Variable	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well
FRAC_CO2	Variable	Fraction of CO_2	Fraction
FRAC_H2S	Variable	Fraction of hydrogen sulfide	Fraction
FRAC_N2	Variable	Fraction of nitrogen	Fraction
FRAC_NGL	Variable	NGL yield	Fraction
FWC_W	Variable	Natural gas facilities costs	K$
GA_CAP	Variable	G & A on capital	K$
GA_EXP	Variable	G & A on expenses	K$
GAS_ADJ	Input	Fraction of annual natural gas drilling which is made available	Fraction
GAS_CASE	Input	Filter for all natural gas processes	
GAS_DWCA	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCB	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCC	Estimated	Horizontal natural gas drilling and completion costs	

GAS_DWCD	Input	Maximum depth range for natural gas well drilling cost equations	Ft
GAS_DWCK	Estimated	Constant for natural gas well drilling cost equations	
GAS_DWCM	Input	Minimum depth range for natural gas well drilling cost equations	Ft
GAS_FILTER	Input	Filter for all natural gas processes	
GAS_OAM	Input	Process specific operating cost for natural gas production	$/Mcf
GAS_SALES	Input	Will produced natural gas be sold?	
GASA0	Estimated	Natural gas footage A0	
GASA1	Estimated	Natural gas footage A1	
GASD0	Input	Natural gas drywell footage A0	
GASD1	Input	Natural gas drywell footage A1	
GASPRICE2	Variable	Natural gas price dummy to shift price track	K$
GASPRICEC	Variable	Annual natural gas prices used by cashflow	K$
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	K$
GASPRICEO	Variable	Annual natural gas prices used by the model	K$
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G & G cost	K$
GG_FAC	Input	G & G factor	
GGCTC	Input	G & G tangible depleted tax credit	K$
GGCTCAB	Input	G & G tangible tax credit rate addback	%
GGCTCR	Input	G & G tangible depleted tax credit rate	K$
GGETC	Input	G & G intangible depleted tax credit	K$
GGETCAB	Input	G & G intangible tax credit rate addback	%
GGETCR	Input	G & G intangible depleted tax credit rate	K$
GGLA	Variable	G & G and lease acquisition addback	K$
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	K$

GMULT_OAM	Input	Natural gas price adjustment factor, O & M	K$
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	K$
GNA_CAP2	Input	G & A capital multiplier	Fraction
GNA_EXP2	Input	G & A expense multiplier	Fraction
GPROD	Variable	Well level natural gas production	MMcf
GRAVPEN	Variable	Gravity penalty	K$
GREMRES	Variable	Remaining proven natural gas reserves	MMcf
GROSS_REV	Variable	Gross revenue	K$
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	%
H_SUCCESS	Input	Horizontal development well success rate by region	%
H2SPRICE	Input	H_2S price	$/Metric ton
HOR_ADJ	Input	Fraction of annual horizontal drilling which is made available	Fraction
HOR_VERT	Input	Split between horizontal and vertical drilling	
HORMUL	Input	Horizontal drilling constraint multiplier	
IAMORYR	Input	Number of years in default amortization schedule	
ICAP	Variable	Other intangible costs	K$
ICST	Variable	Intangible cost	K$
IDCA	Variable	Intangible drilling capital addback	K$
IDCTC	Input	Intangible drilling cost tax credit	K$
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	%
IDCTCR	Input	Intangible drilling cost tax credit rate	K$
IDEPRYR	Input	Number of years in default depreciation schedule	
IGREMRES	Variable	Remaining inferred natural gas reserves	MMcf
II_DRL	Variable	Intangible drilling cost	K$
IINFARSV	Variable	Initial inferred AD gas reserves	Bcf
IINFRESV	Variable	Initial inferred reserves	MMBbl
IMP_CAPCR	Input	Capacity for NGL cryogenic expander plant	MMCf/D

IMP_CAPST	Input	Capacity for NGL straight refrigeration	MMCf/D
IMP_CAPSU	Input	Capacity for Claus Sulfur Recovery	Long ton/day
IMP_CAPTE	Input	Natural gas processing plant capacity	MMcf/D
IMP_CO2_LIM	Input	Limit on CO_2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on H_2O in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H_2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N^2 in natural gas	Fraction
IMP_NGL_LIM	Input	Limit on NGL in natural gas	Fraction
IMP_OP_FAC	Input	Natural gas processing operating factor	
IMP_PLT_LFE	Input	Natural gas processing plant life	Years
IMP_THRU	Input	Throughput	
IND_SRCCO2	Input	Use industrial source of CO_2?	
INDUSTRIAL	Variable	Natural or industrial CO_2 source	
INFLFAC	Input	Annual Inflation Factor	
INFR_ADG	Input	Adjustment factor for inferred AD gas reserves	Tcf
INFR_CBM	Input	Adjustment factor for inferred coalbed methane reserves	Tcf
INFR_DNAG	Input	Adjustment factor for inferred deep non-associated gas reserves	Tcf
INFR_OIL	Input	Adjustment factor for inferred crude oil reserves	Bbl?
INFR_SHL	Input	Adjustment factor for inferred shale gas reserves	Tcf
INFR_SNAG	Input	Adjustment factor for inferred shallow non-associated gas reserves	Tcf
INFR_THT	Input	Adjustment factor for inferred tight gas reserves	Tcf
INFARSV	Variable	Inferred AD gas reserves	Bcf
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMBbl, Bcf
INJ	Variable	Injectant cost	K$
INJ_OAM	Input	Process specific operating cost for injection	$/Bbl
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	K$
INTANG_M	Variable	Intangible cost multiplier	

INTCAP	Variable	Intangible to be capitalized	K$
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternate minimum tax reduction for independents	K$
IREMRES	Variable	Remaining inferred crude oil reserves	MBbl
IUNDARES	Variable	Initial undiscovered resource	MMBbl/Tcf
IUNDRES	Variable	Initial undiscovered resource	MMBbl/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	K$
LACTC	Input	Lease acquisition tangible depleted tax credit	K$
LACTCAB	Input	Lease acquisition tangible credit rate addback	%
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	K$
LAETC	Input	Lease acquisition intangible expensed tax credit	K$
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	%
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	K$
LAST_ASR	Variable	Last year a decline reservoir will be considered for ASR	
LAST_DEC	Variable	Last year a decline reservoir will be considered for EOR	
LBC_FRAC	Input	Lease bonus fraction	Fraction
LEASCST	Variable	Lease cost by project	K$
LEASL48	Variable	Lease equipment costs	1987$/well
MARK_PEN_FAC	Input	Ultimate market penetration	
MAXWELL	Input	Maximum number of dryholes per play per year	
MAX_API_CASE	Input	Maximum API gravity	
MAX_DEPTH_CASE	Input	Maximum depth	
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	
MIN_DEPTH_CASE	Input	Minimum depth	
MIN_PERM_CASE	Input	Minimum permeability	
MIN_RATE_CASE	Input	Minimum production rate	
MOB_RAT_ FAC	Input	Change in mobility ratio	
MPRD	Input	Maximum depth range for new producer equations	Ft

N_CPI	Input	Number of years	
N2PRICE	Input	N_2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO_2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/Yr
NAT_DRCAP_D	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_DRCAP_G	Variable	National natural gas well drilling footage constraints	Ft
NAT_DRCAP_O	Variable	National crude oil well drilling footage constraints	Ft
NAT_DUAL	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_EXP	Variable	National exploratory drilling constraint	Bcf/Yr
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPCDRCAP	Variable	National conventional exploratory drilling footage constraints	Ft
NAT_EXPCDRCAPG	Variable	National high-permeability natural gas exploratory drilling footage constraints	Ft
NAT_EXPCG	Variable	National conventional exploratory drilling natural gas constraint	Bcf/Yr
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/Yr
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPUDRCAP	Variable	National continuous exploratory drilling footage constraints	Ft
NAT_EXPUDRCAPG	Variable	National continuous natural gas exploratory drilling footage constraints	Ft
NAT_EXPUG	Variable	National continuous exploratory drilling natural gas constraint	Bcf/Yr
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/Yr
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/Yr

NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	MBbl
NAT_HOR	Variable	Horizontal drilling constraint	MBbl/Yr
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	MBbl/Yr
NAT_OIL	Variable	National crude oil drilling constraint	MBbl/Yr
NAT_SRCCO2	Input	Use natural source of CO_2?	
NAT_TOT	Variable	Total national footage	Ft
NET_REV	Variable	Net revenue	K$
NEW_ECAP	Variable	New environmental capital cost	K$
NEW_EOAM	Variable	New environmental O & M cost	K$
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/Gal
NGLPROD	Variable	Annual NGL production	MBbl
NIAT	Variable	Net income after taxes	K$
NIBT	Variable	Net income before taxes	K$
NIBTA	Variable	Net operating income after adjustments before addback	K$
NIL	Input	Net income limitations	K$
NILB	Variable	Net income depletable base	K$
NILL	Input	Net income limitation limit	K$
NOI	Variable	Net operating income	K$
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	K$
NPRA	Estimated	Constant for new producer equipment	
NPRB	Estimated	Constant for new producer equipment	
NPRC	Estimated	Constant for new producer equipment	
NPRK	Estimated	Constant for new producer equipment	
NPRM	Input	Minimum depth range for new producer equations	Ft
NPROD	Variable	Well level NGL production	MMcf
NRDL48	Variable	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF
NREG	Input	Number of regions	

NSHUT	Input	Number of years after economics life in which EOR can be considered	
NTECH	Input	Number of technology impacts	
NUMPACK	Input	Number of packages per play per year	
NWELL	Input	Number of wells in continuous exploration drilling package	
OAM	Variable	Variable O & M cost	K$
OAM_COMP	Variable	Compression O & M	K$
OAM_M	Variable	O & M cost multiplier	
OIA	Variable	Other intangible capital addback	K$
OIL_ADJ	Input	Fraction of annual crude oil drilling which is made available	Fraction
OIL_CASE	Input	Filter for all crude oil processes	
OIL_DWCA	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCB	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCC	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCD	Input	Maximum depth range for crude oil well drilling cost equations	Ft
OIL_DWCK	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCM	Input	Minimum depth range for crude oil well drilling cost equations	Ft
OIL_FILTER	Input	Filter for all crude oil processes	
OIL_OAM	Input	Process specific operating cost for crude oil production	$/Bbl
OIL_RAT_ FAC	Input	Change in crude oil production rate	
OIL_RAT_CHG	Variable	Change in crude oil production rate	
OIL_SALES	Input	Sell crude oil produced from the reservoir?	
OILA0	Estimated	Oil footage A0	
OILA1	Estimated	Oil footage A1	

OILCO2	Input	Fixed crude oil price used for economic pre-screening of industrial CO_2 projects	K$
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cashflow	K$
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	K$
OILPRICEO	Variable	Annual crude oil prices used by the model	K$
OILPROD	Variable	Annual crude oil production	MBbl
OINJ	Variable	Well level injection	MMcf
OITC	Input	Other intangible tax credit	K$
OITCAB	Input	Other intangible tax credit rate addback	%
OITCR	Input	Other intangible tax credit rate	K$
OMGA	Estimated	Fixed annual cost for natural gas	$/Well
OMGB	Estimated	Fixed annual cost for natural gas	$/Well
OMGC	Estimated	Fixed annual cost for natural gas	$/Well
OMGD	Input	Maximum depth range for fixed annual O & M natural gas cost	Ft
OMGK	Estimated	Constant for fixed annual O & M cost for natural gas	
OMGM	Input	Minimum depth range for fixed annual O & M cost for natural gas	Ft
OML_W	Variable	Variable annual operating cost for lifting	K$
OMLA	Estimated	Lifting cost	$/Well
OMLB	Estimated	Lifting cost	$/Well
OMLC	Estimated	Lifting cost	$/Well
OMLD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMLK	Estimated	Constant for fixed annual operating cost for crude oil	
OMLM	Input	Minimum depth range for annual operating cost for crude oil	Ft
OMO_W	Variable	Fixed annual operating cost for crude oil	K$

OMOA	Estimated	Fixed annual cost for crude oil	$/Well
OMOB	Estimated	Fixed annual cost for crude oil	$/Well
OMOC	Estimated	Fixed annual cost for crude oil	$/Well
OMOD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMOK	Estimated	Constant for fixed annual operating cost for crude oil	
OMOM	Input	Minimum depth range for fixed annual operating cost for crude oil	Ft
OMSWRA	Estimated	Secondary workover cost	$/Well
OMSWRB	Estimated	Secondary workover cost	$/Well
OMSWRC	Estimated	Secondary workover cost	$/Well
OMSWRD	Input	Maximum depth range for variable operating cost for secondary workover	Ft
OMSWRK	Estimated	Constant for variable operating cost for secondary workover	
OMSWRM	Input	Minimum depth range for variable operating cost for secondary workover	Ft
OMULT_INT	Input	Crude oil price adjustment factor, intangible costs	
OMULT_OAM	Input	Crude oil price adjustment factor, O & M	
OMULT_TANG	Input	Crude oil price adjustment factor, tangible costs	
OPCOST	Variable	AOAM by project	K$
OPERL48	Variable	Operating Costs	1987$/Well
OPINJ_W	Variable	Variable annual operating cost for injection	K$
OPINJA	Input	Injection cost	$/Well
OPINJB	Input	Injection cost	$/Well
OPINJC	Input	Injection cost	$/Well
OPINJD	Input	Maximum depth range for variable annual operating cost for injection	Ft
OPINJK	Input	Constant for variable annual operating cost for injection	
OPINJM	Input	Minimum depth range for variable annual operating cost for injection	Ft

OPROD	Variable	Well level crude oil production	MBbl
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	K$
OPSECA	Estimated	Annual cost for secondary production	$/Well
OPSECB	Estimated	Annual cost for secondary production	$/Well
OPSECC	Estimated	Annual cost for secondary production	$/Well
OPSECD	Input	Maximum depth range for fixed annual operating cost for secondary operations	Ft
OPSECK	Estimated	Constant for fixed annual operating cost for secondary operations	
OPSECM	Input	Minimum depth range for fixed annual operating cost for secondary operations	Ft
OPT_RPT	Input	Report printing options	
ORECY	Variable	Well level recycled injectant	MBbl
OTC	Variable	Other tangible costs	K$
PATT_DEV	Input	Pattern development	
PATT_DEV_MAX	Input	Maximum pattern development schedule	
PATT_DEV_MIN	Input	Minimum pattern development schedule	
PATDEV	Variable	Annual number of patterns developed for base and advanced technology	
PATN	Variable	Patterns initiated each year	
PATNDCF	Variable	DCF by project	K$
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	%
PGGC	Input	Percent of G & G depleted	%
PIIC	Input	Intangible investment to capitalize	%
PLAC	Input	Percent of lease acquisition cost capitalized	%
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	K$
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	

POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	$/Lb
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	K$
PRO_REGEXP	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGEXPG	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGGAS	Input	Regional natural gas well drilling footage constraint	Ft
PRO_REGOIL	Input	Regional crude oil well drilling footage constraint	Ft
PROB_IMP_FAC	Input	Probability of industrial implementation	
PROB_RD_FAC	Input	Probability of successful R & D	
PROC_CST	Variable	Processing cost	$/Mcf
PROC_OAM	Variable	Processing and treating cost	K$
PROCESS_CASE	Input	Filter for crude oil and natural gas processes	
PROCESS_FILTER	Input	Filter for crude oil and natural gas processes	
PROD_IND_ FAC	Input	Production impact	
PROVACC	Input	Year file for resource access	
PROVNUM	Input	Province number	
PRRATL48	Variable	Production to reserves ratio	Fraction
PSHUT	Input	Number of years prior to economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	K$
PSIA	Estimated	Cost to convert a producer to an injector	
PSIB	Estimated	Cost to convert a producer to an injector	
PSIC	Estimated	Cost to convert a producer to an injector	
PSID	Input	Maximum depth range for producer to injector	Ft
PSIK	Estimated	Constant for producer to injector	
PSIM	Input	Minimum depth range for producer to injector	Ft
PSW_W	Variable	Cost to convert a primary to secondary well	K$

PSWA	Estimated	Cost to convert a primary to secondary well	
PSWB	Estimated	Cost to convert a primary to secondary well	
PSWC	Estimated	Cost to convert a primary to secondary well	
PSWD	Input	Maximum depth range for producer to injector	Ft
PSWK	Estimated	Constant for primary to secondary	
PSWM	Input	Minimum depth range for producer to injector	Ft
PWHP	Input	Produced water handling plant multiplier	K$
PWP_F	Variable	Cost for a produced water handling plant	K$
RDEPTH	Variable	Reservoir depth	ft
RDR	Input	Depth interval	
RDR_FOOTAGE	Variable	Footage available in this interval	Ft
RDR_FT	Variable	Running total of footage used in this bin	Ft
REC_EFF_ FAC	Input	Recovery efficiency factor	
RECY_OIL	Input	Produced water recycling cost	K$
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
REG_EXP	Variable	Regional exploratory drilling constraints	MBbl/Yr
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/Yr
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/Yr
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/Yr
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/Yr
REG_HADG	Variable	Regional historical AD gas	MMcf
REG_HCBM	Variable	Regional historical CBM	MMcf

REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	MBbl
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	MBbl
REG_HSHL	Variable	Regional historical shale gas	MMcf
REG_HTHT	Variable	Regional historical tight gas	MMcf
REG_NAT	Input	Regional or national	
REG_OIL	Variable	Regional crude oil drilling constraint	MBbl/Yr
REGDRY	Variable	Regional dryhole rate	
REGDRYE	Variable	Exploration regional dryhole rate	
REGDRYG	Variable	Development natural gas regional dryhole rate	
REGDRYKD	Variable	Regional dryhole rate for discovered development	
REGDRYUD	Variable	Regional dryhole rate for undiscovered development	
REGDRYUE	Variable	Regional dryhole rate for undiscovered exploration	
REGION_CASE	Input	Filter for OLOGSS region	
REGION_FILTER	Input	Filter for OLOGSS region	
REGSCALE_CBM	Input	Regional historical daily CBM gas production for the last year of history	Bcf
REGSCALE_CNV	Input	Regional historical daily high-permeability natural gas production for the last year of history	Bcf
REGSCALE_GAS	Input	Regional historical daily natural gas production for the last year of history	Bcf
REGSCALE_OIL	Input	Regional historical daily crude oil production for the last year of history	MBbl
REGSCALE_SHL	Input	Regional historical daily shale gas production for the last year of history	Bcf
REGSCALE_THT	Input	Regional historical daily tight gas production for the last year of history	Bcf
REM_AMOR	Variable	Remaining amortization base	K$
REM_BASE	Variable	Remaining depreciation base	K$

REMRES	Variable	Remaining proven crude oil reserves	MBbl
RESADL48	Variable	Total additions to proved reserves	Oil-MMB Gas-BCF
RESBOYL48	Variable	End of year reserves for current year	Oil-MMB Gas-BCF
RES_CHR_ FAC	Input	Reservoir characterization cost	$/Cumulative BOE
RES_CHR_CHG	Variable	Reservoir characterization cost	$/Cumulative BOE
RESV_ADGAS	Input	Historical AD gas reserves	Tcf
RESV_CBM	Input	Historical coalbed methane reserves	Tcf
RESV_CONVGAS	Input	Historical high-permeability dry natural gas reserves	Tcf
RESV_OIL	Input	Historical crude oil and lease condensate reserves	BBbl
RESV_SHL	Input	Historical shale gas reserves	Tcf
RESV_THT	Input	Historical tight gas reserves	Tcf
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	K$
ROYALTY	Variable	Royalty	K$
RREG	Variable	Reservoir region	
RRR	Input	Annual drilling retirement rate	
RUNTYPE	Input	Resources selected to evaluate in the Timing subroutine	
RVALUE	Variable	Reservoir technical crude oil production	MBbl
SCALE_DAY	Input	Number of days in the last year of history	Days
SCALE_GAS	Input	Historical daily natural gas production for the last year of history	Bcf
SCALE_OIL	Input	Historical daily crude oil production for the last year of history	MBbl
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	K$
SFIT	Variable	Alternative minimum tax	K$
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	%

SPLIT_ED	Input	Split exploration and development	
SPLIT_OG	Input	Split crude oil and natural gas constraints	
STARTPR	Variable	First year a pattern is initiated	
STATE_TAX	Variable	State tax	K$
STIM	Variable	Stimulation cost	K$
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	K$
STIM_W	Variable	Natural gas well stimulation cost	K$
STIM_YR	Input	Number of years between stimulations of natural gas/oil wells	
STIMFAC	Input	Stimulation efficiency factor	
STL	Variable	State identification number	
STMGA	Input	Steam generator cost multiplier	
STMM_F	Variable	Cost for steam manifolds and generators	K$
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	%
SUCDEVG	Variable	Final developmental natural gas well success rate by region	Fraction
SUCDEVO	Variable	Final developmental crude oil well success rate by region	Fraction
SUCEXP	Input	Undiscovered exploration well dryhole rate by region	%
SUCEXPD	Input	Exploratory well dryhole rate by region	%
SUCG	Variable	Initial developmental natural gas well success rate by region	Fraction
SUCO	Variable	Initial developmental crude oil well success by region	Fraction
SUCWELLL48	Variable	Successful Lower 48 onshore wells drilled	Wells
SUM_DRY	Variable	Developmental dryholes drilled	
SUM_GAS_CONV	Variable	High-permeability natural gas drilling	MMcf

SUM_GAS_UNCONV	Variable	Low-permeability natural gas drilling	MMcf
SUM_OIL_CONV	Variable	Conventional crude oil drilling	MBbl
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	MBbl
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	K$
TANG_FAC_RATE	Input	Percentage of the well costs which are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs which are tangible	Percent
TCI	Variable	Total capital investments	K$
TCIADJ	Variable	Adjusted capital investments	K$
TCOII	Input	Tax credit on intangible investments	K$
TCOTI	Input	Tax credit on tangible investments	K$
TDTC	Input	Tangible development tax credit	K$
TDTCAB	Input	Tangible development tax credit rate addback	%
TDTCR	Input	Tangible development tax credit rate	K$
TECH01_FAC	Input	WAG ratio applied to CO2EOR	
TECH02_FAC	Input	Recovery Limit	
TECH03_FAC	Input	Vertical Skin Factor for natural gas	
TECH04_FAC	Input	Fracture Half Length	Ft
TECH05_FAC	Input	Fracture Conductivity	Ft
TECH_CO2FLD	Variable	Technical production from CO_2 flood	MBbl
TECH_COAL	Variable	Annual technical coalbed methane gas production	MMcf
TECH_CURVE	Variable	Technology commercialization curve for market penetration	
TECH_CURVE_FAC	Input	Technology commercialization curve for market penetration	
TECH_DECLINE	Variable	Technical decline production	MBbl
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	MBbl

TECH_HORPRF	Variable	Technical production for horizontal profile	MBbl
TECH_INFILL	Variable	Technical production from infill drilling	MBbl
TECH_NGL	Variable	Annual technical NGL production	MBbl
TECH_OIL	Variable	Annual technical crude oil production	MBbl
TECH_PLYFLD	Variable	Technical production from polymer injection	MBbl
TECH_PRFMOD	Variable	Technical production from profile modification	MBbl
TECH_PRIMARY	Variable	Technical production from primary sources	MBbl
TECH_RADIAL	Variable	Technical production from conventional radial flow	MMcf
TECH_SHALE	Variable	Annual technical shale gas production	MMcf
TECH_STMFLD	Variable	Technical production from steam flood	MBbl
TECH_TIGHT	Variable	Annual technical tight gas production	MMcf
TECH_TIGHTG	Variable	Technical tight gas production	MMcf
TECH_UCOALB	Variable	Technical undiscovered coalbed methane production	MMcf
TECH_UCONTO	Variable	Technical undiscovered continuous crude oil production	MBbl
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	MBbl
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf
TECH_UGSHALE	Variable	Annual technical developing shale gas production	MMcf
TECH_UGTIGHT	Variable	Annual technical developing tight gas production	MMcf
TECH_USHALE	Variable	Technical undiscovered shale gas production	MMcf
TECH_UTIGHT	Variable	Technical undiscovered tight gas production	MMcf
TECH_WATER	Variable	Technical production from waterflood	MBbl

TECH_WTRFLD	Variable	Technical production from waterflood	MBbl
TGGLCD	Variable	Total G & G cost	K$
TI	Variable	Tangible costs	K$
TI_DRL	Variable	Tangible drilling cost	K$
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	K$
TORECY	Variable	Annual water injection	MBbl
TORECY_CST	Variable	Water injection cost	K$
TOTHWCAP	Variable	Total horizontal drilling footage constraint	Ft
TOTINJ	Variable	Annual water injection	MBbl
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	K$
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	K$
UMPCO2	Input	CO_2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas or lease condensate	Bcf, MMBbl
UNDRES	Variable	Undiscovered resource	MMBbl, Bcf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO_2 by region	Bcf
USE_RDR	Input	Use rig depth rating	
USEAVAIL	Variable	Used annual CO_2 volume by region across all sources	Bcf
USECAP	Variable	Annual total capital investment constraints, used by projects	MM$
UVALUE	Variable	Reservoir undiscovered crude oil production	MBbl
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	%
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	
WAT_OAM	Input	Process specific operating cost for water production	$/Bbl
WATINJ	Variable	Annual water injection	MBbl

WATPROD	Variable	Annual water production	MBbl
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	MBbl
WPROD	Variable	Well level water production	MBbl
WRK_W	Variable	Cost for well workover	K$
WRKA	Estimated	Constant for workover cost equations	
WRKB	Estimated	Constant for workover cost equations	
WRKC	Estimated	Constant for workover cost equations	
WRKD	Input	Maximum depth range for workover cost	Ft
WRKK	Estimated	Constant for workover cost equations	
WRKM	Input	Minimum depth range for workover cost	Ft
XCAPBASE	Variable	Cumulative cap stream	
XCUMPROD	Variable	Cumulative production	MBbl
XPATN	Variable	Active patterns each year	
XPP1	Variable	Number of new producers drilled per pattern	
XPP2	Variable	Number of new injectors drilled per pattern	
XPP3	Variable	Number of producers converted to injectors	
XPP4	Variable	Number of primary wells converted to secondary wells	
XROY	Input	Royalty rate	Percent
YEARS_STUDY	Input	Number of years of analysis	
YR1	Input	Number of years for tax credit on tangible investments	
YR2	Input	Number of years for tax credit on intangible investments	
YRDI	Input	Years to develop infrastructure	
YRDT	Input	Years to develop technology	
YRMA	Input	Years to reach full capacity	

Appendix 2.B: Cost and Constraint Estimation

The major sections of OLOGSS consist of a series of equations that are used to calculate project economics and the development of crude oil and natural gas resources subject to the availability of regional development constraints. The equations, the estimation techniques, and the statistical results for these equations are documented below. The statistical software included within Microsoft Excel was used for the estimations.

Drilling and Completion Costs for Crude Oil

An average of the 2004 – 2007 Joint Association Survey (JAS) data was used to calculate the equation for vertical drilling and completion costs for crude oil. The data was then categorized by depth, shallower than 10,000 feet and deeper than 10,000 feet, and analyzed at the OLOGSS regional level. The independent variable was depth. The form of the equation is given by.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \quad (2.B\text{-}1)$$

where Drilling Cost = DWC_W

β0 = OIL_DWCK

β1 = OIL_DWCA

β2 = OIL_DWCB

β3 = OIL_DWCC

from equations 2-17 and 2-18 in Chapter 2.

Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β3 is statistically insignificant and is therefore zero.

Northeast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9801
R Square	0.9605
Adjusted R Square	0.9408
Standard Error	206,471.7
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.14939E+12	2.1E+12	48.667	0.001558157
Residual	4	1.70522E+11	4.3E+10		
Total	6	4.31992E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	369,747.752	164,371.850	2.249	0.088	-86,622.611	826,118.116	-86,622.611	826,118.116
β1	-191.612	101.735	-1.883	0.133	-474.073	90.850	-474.073	90.850
β2	0.058	0.012	4.659	0.010	0.023	0.092	0.023	0.092

Northeast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9882
R Square	0.9766
Adjusted R Square	0.9610
Standard Error	175,263.5
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.84403E+12	2E+12	62.5712	0.003582144
Residual	3	92151908386	3E+10		
Total	5	3.93619E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	662,541.506	230,367.167	2.876	0.064	-70,590.321	1,395,673.332	-70,590.321	1,395,673.332
β1	-333.118	123.718	-2.693	0.074	-726.843	60.607	-726.843	60.607
β2	0.072	0.014	5.254	0.013	0.028	0.115	0.028	0.115

Gulf Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9983
R Square	0.9966
Adjusted R Square	0.9944
Standard Error	80,993.4
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.80919E+12	3E+12	442.78	0.00019618
Residual	3	19679782797	7E+09		
Total	5	5.82887E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	267,709.915	101,090.255	2.648	0.077	-54,004.696	589,424.527	-54,004.696	589,424.527
β1	-84.436	49.649	-1.701	0.188	-242.443	73.570	-242.443	73.570
β2	0.042	0.005	8.801	0.003	0.027	0.058	0.027	0.058

Gulf Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9994
R Square	0.9989
Adjusted R Square	0.9986
Standard Error	326,766.1
Observations	11

ANOVA

	df	SS	MS	F	Significance F
Regression	2	7.44232E+14	4E+14	3485.01	1.72754E-12
Residual	8	8.54208E+11	1E+11		
Total	10	7.45086E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	777,824.461	250,235.054	3.108	0.014	200,781.019	1,354,867.903	200,781.019	1,354,867.903
β1	-394.347	58.650	-6.724	0.000	-529.593	-259.100	-529.593	-259.100
β2	0.072	0.003	27.280	0.000	0.066	0.078	0.066	0.078

Mid-continent Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9971
Standard Error	37,632.8
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.4299E+12	1.2E+12	857.881	7.2922E-05
Residual	3	4248673285	1.4E+09		
Total	5	2.43415E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	200,032.471	47,359.921	4.224	0.024	49,311.923	350,753.019	49,311.923	350,753.019
β1	-78.594	24.103	-3.261	0.047	-155.300	-1.888	-155.300	-1.888
β2	0.032	0.002	13.100	0.001	0.024	0.040	0.024	0.040

Mid-continent Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9948
R Square	0.9896
Adjusted R Square	0.9827
Standard Error	1,003,534.4
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.87525E+14	1.44E+14	142.75	0.001060364
Residual	3	3.02124E+12	1.01E+12		
Total	5	2.90547E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	21,757,849.927	8,750,074.627	2.487	0.089	-6,088,818.864	49,604,518.718	-6,088,818.864	49,604,518.718
β1	-3,734.191	1,218.273	-3.065	0.055	-7,611.285	142.902	-7,611.285	142.902
β2	0.184	0.040	4.561	0.020	0.056	0.312	0.056	0.312

Southwest Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9975
R Square	0.9950
Adjusted R Square	0.9916
Standard Error	68,124.0
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.74844E+12	1E+12	296.11	0.000357819
Residual	3	13922652294	5E+09		
Total	5	2.76236E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	29,006.510	89,244.261	0.325	0.767	-255,008.826	313,021.846	-255,008.826	313,021.846
β1	97.615	45.247	2.157	0.120	-46.382	241.612	-46.382	241.612
β2	0.017	0.005	3.632	0.036	0.002	0.032	0.002	0.032

Southwest Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9990
R Square	0.9980
Adjusted R Square	0.9960
Standard Error	454,007.6
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.04291E+14	1E+14	495.56	0.002013869
Residual	2	4.12246E+11	2.1E+11		
Total	4	2.04703E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,414,291.650	6,150,506.244	3.319	0.080	-6,049,219.252	46,877,802.552	-6,049,219.252	46,877,802.552
β1	-3,937.411	926.001	-4.252	0.051	-7,921.677	46.854	-7,921.677	46.854
β2	0.218	0.033	6.532	0.023	0.075	0.362	0.075	0.362

Rocky Mountain Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9857
R Square	0.9717
Adjusted R Square	0.9528
Standard Error	222,506.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.09527E+12	2.5E+12	51.4579	0.00476695
Residual	3	1.48527E+11	5E+10		
Total	5	5.24379E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	789,569.978	290,799.246	2.715	0.073	-135,883.875	1,715,023.832	-135,883.875	1,715,023.832
β1	-326.493	151.436	-2.156	0.120	-808.429	155.442	-808.429	155.442
β2	0.068	0.016	4.365	0.022	0.019	0.118	0.019	0.118

Rocky Mountain Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.997
R Square	0.995
Adjusted R Squ	0.984
Standard Error	1,256,143.7
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.91808E+14	1E+14	92.47	0.073336449
Residual	1	1.5779E+12	2E+12		
Total	3	2.93386E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	9,576,095.367	17,607,685.334	0.544	0.683	-214,149,800.939	233,301,991.674	-214,149,800.939	233,301,991.674
β1	-2,174.253	2,590.097	-0.839	0.555	-35,084.413	30,735.908	-35,084.413	30,735.908
β2	0.168	0.090	1.858	0.314	-0.981	1.317	-0.981	1.317

West Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9974
R Square	0.9947
Adjusted R Square	0.9912
Standard Error	96,155.4
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.22269E+12	3E+12	282.434	0.000383982
Residual	3	27737602892	9E+09		
Total	5	5.25043E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	275,660.065	132,459.016	2.081	0.129	-145,884.037	697,204.167	-145,884.037	697,204.167
β1	155.940	69.753	2.236	0.111	-66.047	377.927	-66.047	377.927
β2	0.021	0.007	2.963	0.059	-0.002	0.044	-0.002	0.044

West Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9858
R Square	0.9718
Adjusted R Square	0.9605
Standard Error	398,422.2
Observations	8

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.73447E+13	1.4E+13	86.13	0.000133627
Residual	5	7.93701E+11	1.6E+11		
Total	7	2.81384E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	31,096.952	402,774.733	0.077	0.941	-1,004,266.767	1,066,460.672	-1,004,266.767	1,066,460.672
β1	285.594	147.065	1.942	0.110	-92.447	663.635	-92.447	663.635
β2	0.012	0.010	1.119	0.314	-0.015	0.038	-0.015	0.038

Northern Great Plains Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9960
R Square	0.9921
Adjusted R Square	0.9868
Standard Error	165,315.1
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.02586E+13	5.1E+12	187.686	0.000705999
Residual	3	81987251875	2.7E+10		
Total	5	1.03406E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	160,337.520	216,299.817	0.741	0.512	-528,025.678	848,700.719	-528,025.678	848,700.719
β1	299.670	107.834	2.779	0.069	-43.506	642.846	-43.506	642.846
β2	0.018	0.011	1.715	0.185	-0.015	0.051	-0.015	0.051

Northern Great Plains Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.998
R Square	0.996
Adjusted R Square	0.993
Standard Error	355,587.1
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	8.90777E+13	4.5E+13	352.25	0.00027612
Residual	3	3.79326E+11	1.3E+11		
Total	5	8.9457E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,070,596.267	2,923,169.366	6.866	0.006	10,767,757.990	29,373,434.543	10,767,757.990	29,373,434.543
β1	-2,685.806	400.873	-6.700	0.007	-3,961.563	-1,410.049	-3,961.563	-1,410.049
β2	0.119	0.013	9.140	0.003	0.078	0.161	0.078	0.161

Drilling and Completion Costs for Natural Gas

An average of the 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for natural gas. The data was then categorized by depth, shallower than 10,000 feet and deeper than 10,000 feet, and analyzed at the OLOGSS regional level. The independent variable was depth. The form of the equation is given by.

$$\text{Drilling Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}2)$$

where Drilling Cost = DWC_W

β0 = GAS_DWCK

β1 = GAS_DWCA

β2 = GAS_DWCB

β3 = GAS_DWCC

from equations 2-24 and 2-25 in Chapter 2.

Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β3 is statistically insignificant and is therefore zero.

Northeast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9722
R Square	0.9451
Adjusted R Square	0.9085
Standard Error	1,230,694.46
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	7.82242E+13	3.9E+13	25.8232	0.0129
Residual	3	4.54383E+12	1.5E+12		
Total	5	8.2768E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	232,181.111	1,521,070.631	0.153	0.888	-4,608,549.041	5,072,911.263	-4,608,549.041	5,072,911.263
β1	-220.610	492.739	-0.448	0.685	-1,788.726	1,347.505	-1,788.726	1,347.505
β2	0.073	0.033	2.191	0.116	-0.033	0.179	-0.033	0.179

Northeast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9764
R Square	0.9534
Adjusted R Square	0.9348
Standard Error	961,446.69
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	9.46462E+13	4.7E+13	51.19445	0.000468
Residual	5	4.6219E+12	9.2E+11		
Total	7	9.92681E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	417,590.494	993,582.136	0.420	0.692	-2,136,489.523	2,971,670.511	-2,136,489.523	2,971,670.511
β1	-257.026	362.989	-0.708	0.511	-1,190.117	676.066	-1,190.117	676.066
β2	0.075	0.025	2.970	0.031	0.010	0.139	0.010	0.139

Gulf Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9980
R Square	0.9959
Adjusted R Square	0.9932
Standard Error	62,376.99
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.86684E+12	1.4E+12	368.404	0.0003
Residual	3	11672666435	3.9E+09		
Total	5	2.87851E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	405,947.944	77,479.703	5.239	0.014	159,372.717	652,523.170	159,372.717	652,523.170
β1	-47.053	38.308	-1.228	0.307	-168.967	74.862	-168.967	74.862
β2	0.028	0.004	7.615	0.005	0.016	0.040	0.016	0.040

Gulf Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.99221
R Square	0.98448
Adjusted R Square	0.97413
Standard Error	1,316,487.81
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.29734E+14	1.6E+14	95.1262	0.001934
Residual	3	5.19942E+12	1.7E+12		
Total	5	3.34934E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	25,781,089.615	10,330,028.187	2.496	0.088	-7,093,701.263	58,655,880.492	-7,093,701.263	58,655,880.492
β1	-4,236.478	1,420.690	-2.982	0.059	-8,757.753	284.796	-8,757.753	284.796
β2	0.198	0.046	4.274	0.024	0.050	0.345	0.050	0.345

Mid-continent Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9999
R Square	0.9998
Adjusted R Square	0.9997
Standard Error	12,974.14
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.3303E+12	1.7E+12	9892.28	1.87E-06
Residual	3	504985203	1.7E+08		
Total	5	3.33081E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	186,449.435	16,841.608	11.071	0.002	132,851.871	240,047.000	132,851.871	240,047.000
β1	-15.173	8.737	-1.737	0.181	-42.978	12.631	-42.978	12.631
β2	0.030	0.001	33.919	0.000	0.028	0.033	0.028	0.033

Mid-continent Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9920
R Square	0.9840
Adjusted R Square	0.9681
Standard Error	306,813.96
Observations	5

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.15973E+13	5.8E+12	61.5995	0.01597
Residual	2	1.8827E+11	9.4E+10		
Total	4	1.17856E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	3,236,030.239	3,638,872.197	0.889	0.468	-12,420,784.051	18,892,844.529	-12,420,784.051	18,892,844.529
β1	-269.256	529.690	-0.508	0.662	-2,548.331	2,009.819	-2,548.331	2,009.819
β2	0.026	0.018	1.426	0.290	-0.053	0.106	-0.053	0.106

Southwest Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.99757
R Square	0.99515
Adjusted R Square	0.99192
Standard Error	52,310.42
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.68567E+12	8.4E+11	308.011	0.00034
Residual	3	8209139679	2.7E+09		
Total	5	1.69388E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	635,099.988	73,224.443	8.673	0.003	402,066.912	868,133.063	402,066.912	868,133.063
β1	-48.313	37.182	-1.299	0.285	-166.642	70.015	-166.642	70.015
β2	0.025	0.004	6.739	0.007	0.013	0.037	0.013	0.037

Southwest Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9774
R Square	0.9553
Adjusted R Square	0.9454
Standard Error	1,842,458.21
Observations	12

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	6.52877E+14	3E+14	96.1626	8.44E-07
Residual	9	3.05519E+13	3E+12		
Total	11	6.83429E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,744,628.415	1,445,115.307	1.207	0.258	-1,524,452.019	5,013,708.848	-1,524,452.019	5,013,708.848
β1	-696.952	329.568	-2.115	0.064	-1,442.486	48.582	-1,442.486	48.582
β2	0.085	0.015	5.604	0.000	0.051	0.120	0.051	0.120

Rocky Mountains Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9969
R Square	0.9939
Adjusted R Square	0.9898
Standard Error	92,055.30
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.12688E+12	2.1E+12	243.498	0.00048
Residual	3	25422533148	8.5E+09		
Total	5	4.15231E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	225,080.924	120,279.676	1.871	0.158	-157,703.045	607,864.893	-157,703.045	607,864.893
β1	72.872	65.609	1.111	0.348	-135.926	281.670	-135.926	281.670
β2	0.025	0.007	3.642	0.036	0.003	0.047	0.003	0.047

Rocky Mountains Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9947
R Square	0.9895
Adjusted R Square	0.9789
Standard Error	1,360,727.34
Observations	5

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.4767E+14	1.7E+14	93.8846	0.010539
Residual	2	3.70316E+12	1.9E+12		
Total	4	3.51373E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-10,904,247.173	15,952,855.338	-0.684	0.565	-79,543,891.524	57,735,397.177	-79,543,891.524	57,735,397.177
β1	834.762	2,334.292	0.358	0.755	-9,208.891	10,878.415	-9,208.891	10,878.415
β2	0.063	0.082	0.769	0.522	-0.289	0.415	-0.289	0.415

West Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9982
Standard Error	26,179.97
Observations	5

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.52682E+12	7.63E+11	1113.832	0.0009
Residual	2	1370781849	6.85E+08		
Total	4	1.52819E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	342,964.088	78,625.892	4.362	0.049	4,663.946	681,264.231	4,663.946	681,264.231
β1	80.178	34.161	2.347	0.143	-66.806	227.161	-66.806	227.161
β2	0.017	0.003	5.176	0.035	0.003	0.030	0.003	0.030

West Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9982
Standard Error	26,179.97
Observations	5

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.52682E+12	7.6E+11	1113.83	0.0009
Residual	2	1370781849	6.9E+08		
Total	4	1.52819E+12			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	342,964.088	78,625.892	4.362	0.049	4,663.946	681,264.231	4,663.946	681,264.231
β1	80.178	34.161	2.347	0.143	-66.806	227.161	-66.806	227.161
β2	0.017	0.003	5.176	0.035	0.003	0.030	0.003	0.030

Northern Great Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.96376
R Square	0.92884
Adjusted R Square	0.89325
Standard Error	715,615.89
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.67362E+13	1.3E+13	26.1041	0.0051
Residual	4	2.04842E+12	5.1E+11		
Total	6	2.87846E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	524,956.371	534,881.480	0.981	0.382	-960,115.773	2,010,028.514	-960,115.773	2,010,028.514
β1	-291.062	300.337	-0.969	0.387	-1,124.934	542.810	-1,124.934	542.810
β2	0.083	0.029	2.853	0.046	0.002	0.164	0.002	0.164

Northern Great Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.989955151
R Square	0.9800112
Adjusted R Square	0.97201568
Standard Error	661882.0131
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.07393E+14	5.4E+13	122.57	5.64894E-05
Residual	5	2.19044E+12	4.4E+11		
Total	7	1.09583E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	408,100.261	450,135.825	0.907	0.406	-749,008.823	1,565,209.344	-749,008.823	1,565,209.344
β1	-175.139	188.973	-0.927	0.397	-660.909	310.631	-660.909	310.631
β2	0.070	0.014	5.131	0.004	0.035	0.105	0.035	0.105

Drilling and Completion Costs for Dryholes

An average of the 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for dryholes. The data was then categorized by depth, shallower than 10,000 feet and deeper than 10,000 feet, and analyzed at the OLOGSS regional level. The independent variable was depth. The form of the equation is given by.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}3)$$

where Drilling Cost = DWC_W

β0 = DRY_DWCK

β1 = DRY_DWCA

β2 = DRY_DWCB

β3 = DRY_DWCC

from equations 2-19 and 2-20 in Chapter 2.

Drilling cost is the cost of drilling on a per well basis. The intercept was held constant at zero based on the assumption that there are no set up costs when drilling a dry hole. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β3 is statistically insignificant and is therefore zero.

Northeast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9855
R Square	0.9712
Adjusted R Square	0.7140
Standard Error	112,311.21
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.70332E+12	8.5E+11	67.5181	0.0032
Residual	4	50455232902	1.3E+10		
Total	6	1.75378E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	271.552	34.435	7.886	0.001	175.943	367.160	175.943	367.160
β2	-0.006	0.005	-1.181	0.303	-0.020	0.008	-0.020	0.008

Northeast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9796
R Square	0.9596
Adjusted R Square	0.7516
Standard Error	200,293.36
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.76812E+12	2.4E+12	59.427	0.00106
Residual	5	2.00587E+11	4E+10		
Total	7	4.96871E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	199.300	48.748	4.088	0.009	73.988	324.612	73.988	324.612
β2	0.007	0.006	1.232	0.273	-0.008	0.022	-0.008	0.022

Gulf Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9937
R Square	0.9874
Adjusted R Square	0.7343
Standard Error	95,819.40
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.88157E+12	1.44E+12	156.9248	0.000921302
Residual	4	36725427267	9.18E+09		
Total	6	2.91829E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	127.840	27.237	4.694	0.009	52.218	203.463	52.218	203.463
β2	0.015	0.004	3.924	0.017	0.004	0.025	0.004	0.025

Gulf Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.99522
R Square	0.99047
Adjusted R Square	0.73808
Standard Error	1,040,546.59
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.49894E+14	2E+14	207.758	0.000607
Residual	4	4.33095E+12	1E+12		
Total	6	4.54225E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	-620.167	124.862	-4.967	0.008	-966.842	-273.493	-966.842	-273.493
β2	0.089	0.007	12.508	0.000	0.069	0.108	0.069	0.108

Mid-Continent Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.9942
R Square	0.9885
Adjusted R Square	0.7356
Standard Error	95,976.60
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	3.16798E+12	1.6E+12	171.958	0.0008042
Residual	4	36846034372	9.2E+09		
Total	6	3.20483E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	-6.091	23.493	-0.259	0.808	-71.317	59.135	-71.317	59.135
β2	0.022	0.003	7.790	0.001	0.014	0.030	0.014	0.030

Mid-Continent Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9054
R Square	0.8198
Adjusted R Square	0.6886
Standard Error	1,392,474.47
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	7.93681E+13	4E+13	20.4664	0.000714
Residual	9	1.74509E+13	1.9E+12		
Total	11	9.6819E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	65.959	149.573	0.441	0.670	-272.400	404.317	-272.400	404.317
β2	0.021	0.010	2.054	0.070	-0.002	0.044	-0.002	0.044

Southwest Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.99505
R Square	0.99012
Adjusted R Square	0.73764
Standard Error	112,836.27
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.1016E+12	2.6E+12	200.345	0.000641
Residual	4	50928093429	1.3E+10		
Total	6	5.15253E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	28.973	27.801	1.042	0.356	-48.215	106.161	-48.215	106.161
β2	0.024	0.003	7.415	0.002	0.015	0.034	0.015	0.034

Southwest Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.99505
R Square	0.99012
Adjusted R Square	0.73764
Standard Error	112,836.27
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.1016E+12	2.6E+12	200.345	0.000641
Residual	4	50928093429	1.3E+10		
Total	6	5.15253E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	28.973	27.801	1.042	0.356	-48.215	106.161	-48.215	106.161
β2	0.024	0.003	7.415	0.002	0.015	0.034	0.015	0.034

Rocky Mountain Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.98513
R Square	0.97048
Adjusted R Square	0.71310
Standard Error	243,912.72
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	7.82323E+12	3.9E+12	65.7487	0.00333128
Residual	4	2.37974E+11	5.9E+10		
Total	6	8.0612E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	62.848	72.119	0.871	0.433	-137.386	263.082	-137.386	263.082
β2	0.040	0.010	3.975	0.016	0.012	0.068	0.012	0.068

Rocky Mountain Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9089
R Square	0.8260
Adjusted R Square	0.6304
Standard Error	1,194,614.27
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	4.06587E+13	2E+13	14.2452	0.008612
Residual	6	8.56262E+12	1.4E+12		
Total	8	4.92213E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	-107.925	263.735	-0.409	0.697	-753.261	537.412	-753.261	537.412
β2	0.063	0.028	2.221	0.068	-0.006	0.131	-0.006	0.131

West Coast Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.95101
R Square	0.90442
Adjusted R Square	0.74791
Standard Error	1,079,558.20
Observations	9

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	7.71946E+13	3.9E+13	33.1181	0.000573
Residual	7	8.15812E+12	1.2E+12		
Total	9	8.53527E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	45.073	161.019	0.280	0.788	-335.675	425.822	-335.675	425.822
β2	0.036	0.013	2.803	0.026	0.006	0.066	0.006	0.066

West Coast Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9531
R Square	0.9083
Adjusted R Square	0.7264
Standard Error	970,427.49
Observations	8

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.59997E+13	2.8E+13	29.73239	0.001675
Residual	6	5.65038E+12	9.42E+11		
Total	8	6.16501E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	-76.874	162.895	-0.472	0.654	-475.464	321.715	-475.464	321.715
β2	0.050	0.015	3.464	0.013	0.015	0.086	0.015	0.086

Northern Great Plains Region Shallower than 10,000 Feet:

Regression Statistics	
Multiple R	0.95783
R Square	0.91744
Adjusted R Square	0.79716
Standard Error	1,062,736.27
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	1.12957E+14	5.6E+13	50.007	3.00913E-05
Residual	9	1.01647E+13	1.1E+12		
Total	11	1.23121E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.000	-	-	-	-	-	-	-
β1	529.235	116.962	4.525	0.001	264.649	793.820	264.649	793.820
β2	0.000	0.008	0.053	0.959	-0.018	0.019	-0.018	0.019

Northern Great Plains Region Deeper than 10,000 Feet:

Regression Statistics	
Multiple R	0.9960
R Square	0.9920
Adjusted R Square	0.4879
Standard Error	178,297.25
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	7.83735E+12	3.92E+12	123.268	0.06356
Residual	2	63579817449	3.18E+10		
Total	4	7.90093E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.000	-	-	-	-	-	-	-
X Variable 1	631.533	30.992	20.377	0.002	498.184	764.882	498.184	764.882
X Variable 2	-0.008	0.002	-4.070	0.055	-0.016	0.000	-0.016	0.000

Drilling and Completion Costs for Horizontal Wells

The costs of horizontal drilling for crude oil, natural gas, and dryholes are based upon cost estimates developed for the Department of Energy's Comprehensive Oil and Gas Analysis Model. The form of the equation is as follows:

$$Cost = \beta 0 + \beta 1 * Depth^2 + \beta 2 * Depth^2 * nlat + \beta 3 * Depth^2 * nlat * latlen \qquad (2.B\text{-}4)$$

Where, nlat is the number of laterals per pattern and latlen is the length of those laterals. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Regression Statistics	
Multiple R	1
R Square	1
Adjusted R Square	1
Standard Error	3.12352E-12
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	147,510,801.46	49,170,267.15	5.04E+30	0.00
Residual	116	0.00	0.00		
Total	119	147,510,801.46			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	172.88	4.37E-13	3.95E+14	0.00	172.88	172.88	172.88	172.88
β1	8.07E-06	8.81E-21	9.16E+14	0.00	8.07E-06	8.07E-06	8.07E-06	8.07E-06
β2	1.15E-06	3.20E-21	3.60E+14	0.00	1.15E-06	1.15E-06	1.15E-06	1.15E-06
β3	9.22E-10	1.48E-24	6.23E+14	0.00	9.22E-10	9.22E-10	9.22E-10	9.22E-10

Cost to Equip a Primary Producer

The cost to equip a primary producer was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B\text{-}5)$$

where Cost = NPR_W
β0 = NPRK
β1 = NPRA
β2 = NPRB
β3 = NPRC
from equation 2-21 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS regions 2 and 4:

Regression Statistics	
Multiple R	0.921
R Square	0.849
Adjusted R Square	0.697
Standard Error	621.17
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2,163,010.81	2,163,010.81	5.61	0.254415
Residual	1	385,858.01	385,858.01		
Total	2	2,548,868.81			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	51,315.4034	760.7805	67.4510	0.0094	41,648.8117	60,981.9952	41,648.8117	60,981.9952
β1	0.3404	0.1438	2.3676	0.2544	-1.4864	2.1672	-1.4864	2.1672

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.995
R Square	0.990
Adjusted R Square	0.981
Standard Error	1,193.14
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	145,656,740.81	145,656,740.81	102.32	0.06
Residual	1	1,423,576.87	1,423,576.87		
Total	2	147,080,317.68			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	45,821.717	1,461.289	31.357	0.020	27,254.360	64,389.074	27,254.360	64,389.074
β1	2.793	0.276	10.115	0.063	-0.716	6.302	-0.716	6.302

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9998
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	224.46
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	105,460,601.42	105,460,601.42	2,093.17	0.01
Residual	1	50,383.23	50,383.23		
Total	2	105,510,984.64			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	62,709.378	274.909	228.110	0.003	59,216.346	66,202.411	59,216.346	66,202.411
β1	2.377	0.052	45.751	0.014	1.717	3.037	1.717	3.037

West Coast, applied to OLOGSS regions 6:

Regression Statistics	
Multiple R	0.9095
R Square	0.8272
Adjusted R Square	0.7408
Standard Error	2,257.74
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,812,671.60	48,812,671.60	9.58	0.09
Residual	2	10,194,785.98	5,097,392.99		
Total	3	59,007,457.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106,959.788	2,219.144	48.199	0.000	97,411.576	116,508.001	97,411.576	116,508.001
β1	0.910	0.294	3.095	0.090	-0.355	2.174	-0.355	2.174

Workover Costs

Workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Workover costs consist of the total of workover rig services, remedial services, equipment repair and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}6)$$

where Cost = WRK_W

β0 = WRKK

β1 = WRKA

β2 = WRKB

β3 = WRKC

from equation 2-22 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9898
R Square	0.9798
Adjusted R Square	0.9595
Standard Error	747.71
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	27,074,389.00	27,074,389.00	48.43	0.09
Residual	1	559,069.20	559,069.20		
Total	2	27,633,458.19			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	389.821	915.753	0.426	0.744	-11,245.876	12,025.518	-11,245.876	12,025.518
β1	1.204	0.173	6.959	0.091	-0.995	3.403	-0.995	3.403

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.7558
R Square	0.5713
Adjusted R Square	0.4284
Standard Error	978.19
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,824,956.55	3,824,956.55	4.00	0.14
Residual	3	2,870,570.06	956,856.69		
Total	4	6,695,526.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,949.479	1,043.913	1.867	0.159	-1,372.720	5,271.678	-1,372.720	5,271.678
β1	0.364	0.182	1.999	0.139	-0.216	0.945	-0.216	0.945

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9762
R Square	0.9530
Adjusted R Square	0.9060
Standard Error	2,405.79
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	117,342,912.53	117,342,912.53	20.27	0.14
Residual	1	5,787,839.96	5,787,839.96		
Total	2	123,130,752.49			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-2,738.051	2,946.483	-0.929	0.523	-40,176.502	34,700.400	-40,176.502	34,700.400
β1	2.507	0.557	4.503	0.139	-4.568	9.582	-4.568	9.582

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9839
R Square	0.9681
Adjusted R Square	0.9363
Standard Error	1,034.20
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	32,508,694.98	32,508,694.98	30.39	0.11
Residual	1	1,069,571.02	1,069,571.02		
Total	2	33,578,265.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,736.081	1,266.632	1.371	0.401	-14,357.935	17,830.097	-14,357.935	17,830.097
β1	1.320	0.239	5.513	0.114	-1.722	4.361	-1.722	4.361

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9985
R Square	0.9969
Adjusted R Square	0.9939
Standard Error	273.2
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	24,387,852.65	24,387,852.65	326.67	0.04
Residual	1	74,656.68	74,656.68		
Total	2	24,462,509.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	1,326.648	334.642	3.964	0.157	-2,925.359	5,578.654	-2,925.359	5,578.654
β1	1.143	0.063	18.074	0.035	0.339	1.947	0.339	1.947

Cost to Convert a Primary to Secondary Well

The cost to convert a primary to secondary well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data was analyzed on a regional level. The secondary operations costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}7)$$

where Cost = PSW_W

$\beta0$ = PSWK

$\beta1$ = PSWA

$\beta2$ = PSWB

$\beta3$ = PSWC

from equation 2-35 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	1.00000
R Square	0.99999
Adjusted R Square	0.99999
Standard Error	552.23
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	44,056,261,873.48	44,056,261,873.48	144,469.3	0.00
Residual	1	304,952.52	304,952.52		
Total	2	44,056,566,825.99			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-25,175.8	676.335	-37.224	0.017	-33,769.389	-16,582.166	-33,769.389	-16,582.166
β1	48.581	0.128	380.091	0.002	46.957	50.205	46.957	50.205

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.996760
R Square	0.993531
Adjusted R Square	0.991914
Standard Error	16909.05
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	175,651,490,230.16	175,651,490,230.16	614.35	0.00
Residual	4	1,143,664,392.16	285,916,098.04		
Total	5	176,795,154,622.33			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-10,733.7	14,643.670	-0.733	0.504	-51,391.169	29,923.692	-51,391.169	29,923.692
β1	68.593	2.767	24.786	0.000	60.909	76.276	60.909	76.276

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.999830
R Square	0.999660
Adjusted R Square	0.999320
Standard Error	4047.64
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,164,743,341	48,164,743,341	2,939.86	0.01
Residual	1	16,383,350	16,383,350		
Total	2	48,181,126,691			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-32,919.3	4,957.320	-6.641	0.095	-95,907.768	30,069.148	-95,907.768	30,069.148
β1	50.796	0.937	54.220	0.012	38.893	62.700	38.893	62.700

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.999208
R Square	0.998416
Adjusted R Square	0.996832
Standard Error	9968.98
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	62,643,414,406.49	62,643,414,406.49	630.34	0.03
Residual	1	99,380,639.94	99,380,639.94		
Total	2	62,742,795,046.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-115.557	12,209.462	-0.009	0.994	-155,250.815	155,019.701	-155,250.815	155,019.701
β1	57.930	2.307	25.107	0.025	28.612	87.248	28.612	87.248

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.999970
R Square	0.999941
Adjusted R Square	0.999882
Standard Error	2317.03
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	90,641,249,203.56	90,641,249,203.56	16,883.5	0.00
Residual	1	5,368,613.99	5,368,613.99		
Total	2	90,646,617,817.55			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-47,775.5	2,837.767	-16.836	0.038	-83,832.597	-11,718.412	-83,832.597	-11,718.412
β1	69.683	0.536	129.937	0.005	62.869	76.498	62.869	76.498

Cost to Convert a Producer to an Injector

The cost to convert a production well to an injection well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a production to an injection well consist of tubing replacement, distribution lines and header costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}8)$$

where Cost = PSI_W
β0 = PSIK
β1 = PSIA
β2 = PSIB
β3 = PSIC
from equation 2-36 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994714
R Square	0.989456
Adjusted R Square	0.978913
Standard Error	3204.94
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	963,939,802.16	963,939,802.16	93.84	0.07
Residual	1	10,271,635.04	10,271,635.04		
Total	2	974,211,437.20			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,129.3	3,925.233	2.835	0.216	-38,745.259	61,003.937	-38,745.259	61,003.937
β1	7.186	0.742	9.687	0.065	-2.239	16.611	-2.239	16.611

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.988716
R Square	0.977560
Adjusted R Square	0.971950
Standard Error	4435.41
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,428,080,322.21	3,428,080,322.21	174.25	0.00
Residual	4	78,691,571.93	19,672,892.98		
Total	5	3,506,771,894.14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,640.6	3,841.181	6.415	0.003	13,975.763	35,305.462	13,975.763	35,305.462
β1	9.582	0.726	13.201	0.000	7.567	11.598	7.567	11.598

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993556
R Square	0.987154
Adjusted R Square	0.974307
Standard Error	3770.13
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,092,230,257.01	1,092,230,257.01	76.84	0.07
Residual	1	14,213,917.83	14,213,917.83		
Total	2	1,106,444,174.85			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	9,356.411	4,617.453	2.026	0.292	-49,313.648	68,026.469	-49,313.648	68,026.469
β1	7.649	0.873	8.766	0.072	-3.438	18.737	-3.438	18.737

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995436
R Square	0.990893
Adjusted R Square	0.981785
Standard Error	3266.39
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,160,837,008.65	1,160,837,008.65	108.80	0.06
Residual	1	10,669,310.85	10,669,310.85		
Total	2	1,171,506,319.50			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	24,054.311	4,000.496	6.013	0.105	-26,776.589	74,885.211	-26,776.589	74,885.211
β1	7.886	0.756	10.431	0.061	-1.720	17.492	-1.720	17.492

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.998023
R Square	0.996050
Adjusted R Square	0.992100
Standard Error	2903.09
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2,125,305,559.02	2,125,305,559.02	252.17	0.04
Residual	1	8,427,914.12	8,427,914.12		
Total	2	2,133,733,473.15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,125.846	3,555.541	3.129	0.197	-34,051.391	56,303.083	-34,051.391	56,303.083
β1	10.670	0.672	15.880	0.040	2.133	19.208	2.133	19.208

Facilities Upgrade Costs for Crude Oil Wells

The facilities upgrading cost for secondary oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}9)$$

where Cost = FAC_W
β0 = FACUPK
β1 = FACUPA
β2 = FACUPB
β3 = FACUPC
from equation 2-23 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.947660
R Square	0.898060
Adjusted R Square	0.796120
Standard Error	6332.38
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	353,260,332.81	353,260,332.81	8.81	0.21
Residual	1	40,099,063.51	40,099,063.51		
Total	2	393,359,396.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,711.761	7,755.553	2.671	0.228	-77,831.455	119,254.977	-77,831.455	119,254.977
β1	4.350	1.466	2.968	0.207	-14.273	22.973	-14.273	22.973

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.942744
R Square	0.888767
Adjusted R Square	0.851689
Standard Error	6699.62
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,075,905,796.72	1,075,905,796.72	23.97	0.02
Residual	3	134,654,629.89	44,884,876.63		
Total	4	1,210,560,426.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	33,665.6	7,149.747	4.709	0.018	10,911.921	56,419.338	10,911.921	56,419.338
β1	6.112	1.248	4.896	0.016	2.139	10.085	2.139	10.085

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.950784
R Square	0.903990
Adjusted R Square	0.807980
Standard Error	6705.31
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	423,335,427.35	423,335,427.35	9.42	0.20
Residual	1	44,961,183.70	44,961,183.70		
Total	2	468,296,611.04			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	19,032.550	8,212.294	2.318	0.259	-85,314.094	123,379.194	-85,314.094	123,379.194
β1	4.762	1.552	3.068	0.201	-14.957	24.482	-14.957	24.482

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.90132
R Square	0.81238
Adjusted R Square	0.62476
Standard Error	8,531
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	315,132,483.91	315,132,483.91	4.33	0.29
Residual	1	72,780,134.04	72,780,134.04		
Total	2	387,912,617.95			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	37,322	10,448.454	3.572	0.174	-95,437.589	170,081.677	-95,437.589	170,081.677
β1	4.109	1.975	2.081	0.285	-20.980	29.198	-20.980	29.198

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.974616
R Square	0.949876
Adjusted R Square	0.899753
Standard Error	6,765.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	867,401,274.79	867,401,274.79	18.95	0.14
Residual	1	45,771,551.83	45,771,551.83		
Total	2	913,172,826.62			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	23,746.6	8,285.972	2.866	0.214	-81,536.251	129,029.354	-81,536.251	129,029.354
β1	6.817	1.566	4.353	0.144	-13.080	26.713	-13.080	26.713

Natural Gas Well Facilities Costs

Natural gas well facilities costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data was analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \qquad (2.B\text{-}10)$$

where Cost = FWC_W

β0 = FACGK

β1 = FACGA

β2 = FACGB

β3 = FACGC

Q = PEAKDAILY_RATE

from equation 2-28 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9834
R Square	0.9672
Adjusted R Square	0.9562
Standard Error	5,820.26
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8,982,542,532.41	2,994,180,844.14	88.39	0.00
Residual	9	304,879,039.45	33,875,448.83		
Total	12	9,287,421,571.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,477.41	4,694.03	0.74	0.48	-7,141.24	14,096.05	-7,141.24	14,096.05
β1	5.04	0.40	12.51	0.00	4.13	5.95	4.13	5.95
β2	63.87	19.07	3.35	0.01	20.72	107.02	20.72	107.02
β3	0.00	0.00	-3.18	0.01	-0.01	0.00	-0.01	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9621
R Square	0.9256
Adjusted R Square	0.9139
Standard Error	8,279.60
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	16,213,052,116.02	5,404,350,705.34	78.84	0.00
Residual	19	1,302,484,315.70	68,551,806.09		
Total	22	17,515,536,431.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	14,960.60	4,066.98	3.68	0.00	6,448.31	23,472.90	6,448.31	23,472.90
β1	4.87	0.47	10.34	0.00	3.88	5.85	3.88	5.85
β2	28.49	6.42	4.43	0.00	15.04	41.93	15.04	41.93
β3	0.00	0.00	-3.62	0.00	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.9917
R Square	0.9835
Adjusted R Square	0.9765
Standard Error	4,030.43
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6,796,663,629.62	2,265,554,543.21	139.47	0.00
Residual	7	113,710,456.60	16,244,350.94		
Total	10	6,910,374,086.22			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,185.92	3,441.41	2.96	0.02	2,048.29	18,323.54	2,048.29	18,323.54
β1	4.51	0.29	15.71	0.00	3.83	5.18	3.83	5.18
β2	55.38	14.05	3.94	0.01	22.16	88.60	22.16	88.60
β3	0.00	0.00	-3.78	0.01	-0.01	0.00	-0.01	0.00

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9594
R Square	0.9204
Adjusted R Square	0.8806
Standard Error	7,894.95
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4,322,988,996.06	1,440,996,332.02	23.12	0.00
Residual	6	373,981,660.54	62,330,276.76		
Total	9	4,696,970,656.60			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,922.48	8,200.06	0.97	0.37	-12,142.36	27,987.31	-12,142.36	27,987.31
β1	6.51	1.14	5.71	0.00	3.72	9.30	3.72	9.30
β2	89.26	28.88	3.09	0.02	18.59	159.94	18.59	159.94
β3	-0.01	0.00	-2.77	0.03	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Crude Oil Wells

The fixed annual cost for crude oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of supervision and overhead costs, auto usage costs, operative supplies, labor costs, supplies and services costs, equipment usage and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B-11)$$

where Cost = OMO_W
β0 = OMOK
β1 = OMOA
β2 = OMOB
β3 = OMOC
from equation 2-30 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9895
R Square	0.9792
Adjusted R Square	0.9584
Standard Error	165.6
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,290,021.8	1,290,021.8	47.0	0.1
Residual	1	27,419.5	27,419.5		
Total	2	1,317,441.3			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	6,026.949	202.804	29.718	0.021	3,450.097	8,603.802	3,450.097	8,603.802
β1	0.263	0.038	6.859	0.092	-0.224	0.750	-0.224	0.750

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8631
R Square	0.7449
Adjusted R Square	0.6811
Standard Error	2,759.2
Observations	6

ANOVA

	df	SS	MS	F	Significance F
Regression	1	88,902,026.9	88,902,026.9	11.7	0.0
Residual	4	30,452,068.1	7,613,017.0		
Total	5	119,354,095.0			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,171.358	2,389.511	3.001	0.040	536.998	13,805.718	536.998	13,805.718
β1	1.543	0.452	3.417	0.027	0.289	2.797	0.289	2.797

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9888
R Square	0.9777
Adjusted R Square	0.9554
Standard Error	325.8
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	4,654,650.4	4,654,650.4	43.9	0.1
Residual	1	106,147.3	106,147.3		
Total	2	4,760,797.7			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,572.283	399.025	13.965	0.046	502.211	10,642.355	502.211	10,642.355
β1	0.499	0.075	6.622	0.095	-0.459	1.458	-0.459	1.458

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9634
R Square	0.9282
Adjusted R Square	0.8923
Standard Error	455.6
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5,368,949.5	5,368,949.5	25.9	0.0
Residual	2	415,138.5	207,569.2		
Total	3	5,784,088.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,327.733	447.809	14.130	0.005	4,400.964	8,254.501	4,400.964	8,254.501
β1	0.302	0.059	5.086	0.037	0.046	0.557	0.046	0.557

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9908
R Square	0.9817
Adjusted R Square	0.9725
Standard Error	313.1
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10,498,366.6	10,498,366.6	107.1	0.0
Residual	2	196,056.3	98,028.2		
Total	3	10,694,422.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,193.399	307.742	16.876	0.003	3,869.291	6,517.508	3,869.291	6,517.508
β1	0.422	0.041	10.349	0.009	0.246	0.597	0.246	0.597

Fixed Annual Costs for Natural Gas Wells

Fixed annual costs for natural gas wells were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data was analyzed on a regional level. The independent variables are depth and Q which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \qquad (2.B\text{-}12)$$

where Cost = FOAMG_W
β0 = OMGK
β1 = OMGA
β2 = OMGB
β3 = OMGC
Q = PEAKDAILY_RATE
from equation 2-29 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.928
R Square	0.861
Adjusted R Square	0.815
Standard Error	6,471.68
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,344,632,468.49	781,544,156.16	18.66	0.00
Residual	9	376,944,241.62	41,882,693.51		
Total	12	2,721,576,710.11			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,450.28	5,219.40	0.85	0.42	-7,356.84	16,257.40	-7,356.84	16,257.40
β1	2.50	0.45	5.58	0.00	1.49	3.51	1.49	3.51
β2	27.65	21.21	1.30	0.22	-20.33	75.63	-20.33	75.63
β3	0.00	0.00	-1.21	0.26	0.00	0.00	0.00	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.913
R Square	0.834
Adjusted R Square	0.807
Standard Error	6,564.36
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4,100,685,576.61	1,366,895,192.20	31.72	0.00
Residual	19	818,725,806.73	43,090,831.93		
Total	22	4,919,411,383.34			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,145.70	3,224.45	3.46	0.00	4,396.85	17,894.55	4,396.85	17,894.55
β1	2.68	0.37	7.17	0.00	1.90	3.46	1.90	3.46
β2	7.67	5.09	1.51	0.15	-2.99	18.33	-2.99	18.33
β3	0.00	0.00	-1.21	0.24	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS region 3 and 6:

Regression Statistics	
Multiple R	0.934
R Square	0.873
Adjusted R Square	0.830
Standard Error	6,466.88
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,578,736,610.45	859,578,870.15	20.55	0.00
Residual	9	376,384,484.71	41,820,498.30		
Total	12	2,955,121,095.16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	8,193.82	5,410.04	1.51	0.16	-4,044.54	20,432.18	-4,044.54	20,432.18
β1	2.75	0.45	6.14	0.00	1.74	3.77	1.74	3.77
β2	21.21	18.04	1.18	0.27	-19.59	62.01	-19.59	62.01
β3	0.00	0.00	-1.12	0.29	0.00	0.00	0.00	0.00

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.945
R Square	0.893
Adjusted R Square	0.840
Standard Error	6,104.84
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	1,874,387,985.75	624,795,995.25	16.76	0.00
Residual	6	223,614,591.98	37,269,098.66		
Total	9	2,098,002,577.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,534.86	6,340.77	1.19	0.28	-7,980.45	23,050.17	-7,980.45	23,050.17
β1	3.81	0.88	4.33	0.00	1.66	5.97	1.66	5.97
β2	32.27	22.33	1.44	0.20	-22.38	86.92	-22.38	86.92
β3	0.00	0.00	-1.18	0.28	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Secondary Production

The fixed annual cost for secondary oil production was calculated an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}13)$$

where Cost = OPSEC_W

β0 = OPSECK

β1 = OPSECA

β2 = OPSECB

β3 = OPSECC

from equation 2-31 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9972
R Square	0.9945
Adjusted R Square	0.9890
Standard Error	1,969.67
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	698,746,493.71	698,746,493.71	180.11	0.05
Residual	1	3,879,582.16	3,879,582.16		
Total	2	702,626,075.87			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	30,509.3	2,412.338	12.647	0.050	-142.224	61,160.827	-142.224	61,160.827
β1	6.118	0.456	13.420	0.047	0.326	11.911	0.326	11.911

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.935260
R Square	0.874710
Adjusted R Square	0.843388
Standard Error	8414.07
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,977,068,663.41	1,977,068,663.41	27.93	0.01
Residual	4	283,186,316.21	70,796,579.05		
Total	5	2,260,254,979.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	55,732.7	7,286.799	7.648	0.002	35,501.310	75,964.186	35,501.310	75,964.186
β1	7.277	1.377	5.285	0.006	3.454	11.101	3.454	11.101

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.998942
R Square	0.997884
Adjusted R Square	0.995768
Standard Error	1329.04
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	833,049,989.02	833,049,989.02	471.62	0.03
Residual	1	1,766,354.45	1,766,354.45		
Total	2	834,816,343.47			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	28,208.7	1,627.738	17.330	0.037	7,526.417	48,890.989	7,526.417	48,890.989
β1	6.680	0.308	21.717	0.029	2.772	10.589	2.772	10.589

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.989924
R Square	0.979949
Adjusted R Square	0.959899
Standard Error	3639.10
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	647,242,187.96	647,242,187.96	48.87	0.09
Residual	1	13,243,073.43	13,243,073.43		
Total	2	660,485,261.39			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	53,857.06	4,456.973	12.084	0.053	-2,773.909	110,488.034	-2,773.909	110,488.034
β1	5.888	0.842	6.991	0.090	-4.814	16.591	-4.814	16.591

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.992089
R Square	0.984240
Adjusted R Square	0.968480
Standard Error	5193.40
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,684,438,248.88	1,684,438,248.88	62.45	0.08
Residual	1	26,971,430.96	26,971,430.96		
Total	2	1,711,409,679.84			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	35,893.465	6,360.593	5.643	0.112	-44,925.189	116,712.119	-44,925.189	116,712.119
β1	9.499	1.202	7.903	0.080	-5.774	24.773	-5.774	24.773

Lifting Costs

Lifting costs for crude oil wells were calculated using average an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information

Administration (EIA). Lifting costs consist of labor costs for the pumper, chemicals, fuel, power and water costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}14)$$

where Cost = OML_W
β0 = OMLK
β1 = OMLA
β2 = OMLB
β3 = OMLC
from equation 2-32 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9994
R Square	0.9988
Adjusted R Square	0.9976
Standard Error	136.7
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	15,852,301	15,852,301	849	0
Residual	1	18,681	18,681		
Total	2	15,870,982			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,534.515	167.395	45.010	0.014	5,407.565	9,661.465	5,407.565	9,661.465
β1	0.922	0.032	29.131	0.022	0.520	1.323	0.520	1.323

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8546
R Square	0.7304
Adjusted R Square	0.6764
Standard Error	2263.5
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	69,387,339	69,387,339	14	0
Residual	5	25,617,128	5,123,426		
Total	6	95,004,467			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,585.191	1,654.440	7.002	0.001	7,332.324	15,838.058	7,332.324	15,838.058
β1	0.912	0.248	3.680	0.014	0.275	1.549	0.275	1.549

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9997
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	82.0
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	13,261,874	13,261,874	1,972	0
Residual	1	6,726	6,726		
Total	2	13,268,601			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	8,298.339	100.447	82.614	0.008	7,022.045	9,574.634	7,022.045	9,574.634
β1	0.843	0.019	44.403	0.014	0.602	1.084	0.602	1.084

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	1.0000
R Square	1.0000
Adjusted R Square	0.9999
Standard Error	11.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,979,238	3,979,238	30,138	0
Residual	1	132	132		
Total	2	3,979,370			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,137.398	14.073	720.342	0.001	9,958.584	10,316.212	9,958.584	10,316.212
β1	0.462	0.003	173.603	0.004	0.428	0.495	0.428	0.495

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9969
R Square	0.9937
Adjusted R Square	0.9874
Standard Error	1134.3
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	203,349,853	203,349,853	158	0
Residual	1	1,286,583	1,286,583		
Total	2	204,636,436			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,147.313	1,389.199	3.705	0.168	-12,504.063	22,798.689	-12,504.063	22,798.689
β1	3.301	0.263	12.572	0.051	-0.035	6.636	-0.035	6.636

Secondary Workover Costs

Secondary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Secondary workover costs consist of workover rig services, remedial services and equipment repair. The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \quad (2.B\text{-}15)$$

where Cost = SWK_W
$\beta 0$ = OMSWRK
$\beta 1$ = OMSWRA
$\beta 2$ = OMSWRB
$\beta 3$ = OMSWRC
from equation 2-33 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9993
R Square	0.9986
Adjusted R Square	0.9972
Standard Error	439.4
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	136,348,936	136,348,936	706	0
Residual	1	193,106	193,106		
Total	2	136,542,042			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,951.059	538.200	9.199	0.069	-1,887.392	11,789.510	-1,887.392	11,789.510
β1	2.703	0.102	26.572	0.024	1.410	3.995	1.410	3.995

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9924
R Square	0.9849
Adjusted R Square	0.9811
Standard Error	1356.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	480,269,759	480,269,759	261	0
Residual	4	7,358,144	1,839,536		
Total	5	487,627,903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,560.069	1,174.586	8.990	0.001	7,298.889	13,821.249	7,298.889	13,821.249
β1	3.587	0.222	16.158	0.000	2.970	4.203	2.970	4.203

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9989
R Square	0.9979
Adjusted R Square	0.9958
Standard Error	544.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,143,261	140,143,261	473	0
Residual	1	296,583	296,583		
Total	2	140,439,844			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,732.510	666.989	5.596	0.113	-4,742.355	12,207.375	-4,742.355	12,207.375
β1	2.740	0.126	21.738	0.029	1.138	4.342	1.138	4.342

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9983
Standard Error	290.9
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	98,740,186	98,740,186	1,167	0
Residual	1	84,627	84,627		
Total	2	98,824,812			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,291.954	356.287	14.853	0.043	764.922	9,818.987	764.922	9,818.987
β1	2.300	0.067	34.158	0.019	1.444	3.155	1.444	3.155

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9966
Standard Error	454.7
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	120,919,119	120,919,119	585	0
Residual	1	206,762	206,762		
Total	2	121,125,881			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,131.486	556.905	7.419	0.085	-2,944.638	11,207.610	-2,944.638	11,207.610
β1	2.545	0.105	24.183	0.026	1.208	3.882	1.208	3.882

Additional Cost Equations and Factors

The model uses several updated cost equations and factors originally developed for DOE/NETL's Comprehensive Oil and Gas Analysis Model (COGAM). These are:

- The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs. These factors were originally developed based upon the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.
- The G&A factors for capitalized and expensed costs.
- The limits on impurities, such as N2, CO2, and H2S used to calculate natural gas processing costs.
- Cost equations for stimulation, the produced water handling plant, the chemical handling plant, the polymer handling plant, CO_2 recycling plant, and the steam manifolds and pipelines.

Natural and Industrial CO2 Prices

The model uses regional CO_2 prices for both natural and industrial sources of CO_2. The cost equation for natural CO_2 is derived from the equation used in COGAM and updated to reflect current dollar values. This equation is applicable to the natural CO_2 in the Permian basin (Southwest). The cost of CO_2 in other regions and states is calculated using state calibration factors which represent the additional cost of transportation.

The industrial CO_2 costs contain two components: cost of capture and cost of transportation. The capture costs are derived from the *Global Energy Technology Strategy Program Report* and other sources. See the October 12, 2009 Oil and Gas Journal Article, *Study places CO_2 capture cost between \$34 and \$61/ton*. The transportation costs were derived using an external economic model which calculates pipeline tariff based upon average distance, compression rate, and volume of CO_2 transported.

National Crude Oil Drilling Footage Equation

The equation for crude oil drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

Oil Footage = $\beta0 + \beta1$ * Oil Price (2.B-16)

where $\beta0$ = OILA0

$\beta1$ = OILA1

from equation 2-99 in Chapter 2.

Where oil footage is footage of total developmental crude oil wells drilled in the United States in thousands of feet. Crude oil price is a rolling five year average of crude oil prices from 1995 – 2008. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Oil Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9623
R Square	0.9259
Adjusted R Square	0.9167
Standard Error	5,108.20
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,609,812,096.02	2,609,812,096.02	100.02	0.00
Residual	8	208,749,712.88	26,093,714.11		
Total	9	2,818,561,808.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,984.11	4,377.97	0.91	0.39	-6,111.51	14,079.72	-6,111.51	14,079.72
β1	1,282.45	128.23	10.00	0.00	986.74	1,578.16	986.74	1,578.16

Regional Crude Oil Footage Distribution

The regional drilling distributions for crude oil were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Oil
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.6%
Gulf Coast	AL,FL,LA,MS,TX	29.3%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	18.3%
Rocky Mountains	CO,NV,UT,WY,NM	10.7%
West Coast	CA,WA	9.6%
Northern Great Plains	MT,ND,SD	7.6%

National Natural Gas Drilling Footage Equation

The equation for natural gas drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Gas Footage} = \beta 0 + \beta 1 * \text{Gas Price} \qquad (2.B\text{-}17)$$

where $\beta 0 = GASA0$

$\beta 1 = GASA1$

from equation 2-100 in Chapter 2.

Where gas footage is footage of total developmental natural gas wells drilled in the United States in thousands of feet. Gas price is a rolling five year average of natural gas prices from 1995 – 2008. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Gas Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9189
R Square	0.8444
Adjusted R Square	0.7666
Standard Error	9,554.63
Observations	4

ANOVA

	df	SS	MS	F	Significance F
Regression	1	990,785,019.79	990,785,019.79	10.85	0.08
Residual	2	182,581,726.21	91,290,863.10		
Total	3	1,173,366,746.00			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	2,793.29	53,884.13	0.05	0.96	-229,051.57	234,638.14	-229,051.57	234,638.14
β1	30,429.72	9,236.81	3.29	0.08	-9,313.08	70,172.52	-9,313.08	70,172.52

Regional Natural Gas Footage Distribution

The regional drilling distributions for natural gas were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Gas
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	13.2%
Gulf Coast	AL,FL,LA,MS,TX	18.7%
Midcontinent	AR,KS,MO,NE,OK,TX	13.4%
Southwest	TX,NM	34.5%
Rocky Mountains	CO,NV,UT,WY,NM	19.5%
West Coast	CA,WA	0.4%
Northern Great Plains	MT,ND,SD	0.4%

National Exploration Drilling Footage Equation

The equation for exploration well drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Exploration Footage} = \beta 0 + \beta 1 * \text{Oil Price} \qquad (2.B\text{-}18)$$

where $\beta 0 = EXPA0$
$\beta 1 = EXPA1$

Where exploration footage is footage of total exploratory crude oil, natural gas and dry wells drilled in the United States in thousands of feet. Crude oil price is a rolling five year average of oil prices from 1995 – 2008. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Exploration Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9467
R Square	0.8963
Adjusted R Square	0.8834
Standard Error	2,825.10
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	552,044,623.08	552,044,623.08	69.17	0.00
Residual	8	63,849,573.82	7,981,196.73		
Total	9	615,894,196.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,733.91	2,421.24	1.96	0.09	-849.49	10,317.31	-849.49	10,317.31
β1	589.83	70.92	8.32	0.00	426.28	753.37	426.28	753.37

Regional Exploration Footage Distribution

The regional distribution for drilled exploration projects is also estimated using the updated EIA well count file. The percent allocations for each corresponding region are calculated using a 2004 – 2008 average of footage drilled for exploratory fields for both crude oil and natural gas.

Region Name	States Included	Exploration
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	22.3%
Gulf Coast	AL,FL,LA,MS,TX	9.0%
Midcontinent	AR,KS,MO,NE,OK,TX	28.8%
Southwest	TX,NM	14.3%
Rocky Mountains	CO,NV,UT,WY,NM	11.5%
West Coast	CA,WA	0.3%
Northern Great Plains	MT,ND,SD	13.8%

Regional Dryhole Rate for Discovered Projects

The percent allocation for existing regional dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Existing dryhole rates calculate the projects which have already been discovered. The formula for the percentage is given below:

Existing Dryhole Rate = Developed Dryhole / Total Drilling (2.B-19)

Region Name	States Included	Existing
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	5.8%
Gulf Coast	AL,FL,LA,MS,TX	9.4%
Midcontinent	AR,KS,MO,NE,OK,TX	13.2%
Southwest	TX,NM	9.7%
Rocky Mountains	CO,NV,UT,WY,NM	4.3%
West Coast	CA,WA	1.5%
Northern Great Plains	MT,ND,SD	5.2%

Regional Dryhole Rate for First Exploration Well Drilled

The percent allocation for undiscovered regional exploration dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional exploration dryhole rates calculate the rate for the first well drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Exploration = Exploration Dryhole / (Exploration Gas + Exploration Oil)

Region Name	States Included	Undisc. Exp
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	30.8%
Gulf Coast	AL,FL,LA,MS,TX	167.8%
Midcontinent	AR,KS,MO,NE,OK,TX	76.4%
Southwest	TX,NM	86.2%
Rocky Mountains	CO,NV,UT,WY,NM	74.0%
West Coast	CA,WA	466.0%
Northern Great Plains	MT,ND,SD	46.9%

Regional Dryhole Rate for Subsequent Exploration Wells Drilled

The percent allocation for undiscovered regional developed dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional developed dryhole rates calculate the rate for subsequent wells drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Developed = (Developed Dryhole + Explored Dryhole) / Total Drilling (2.B-20)

Region Name	States Included	Undisc. Dev
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.3%
Gulf Coast	AL,FL,LA,MS,TX	11.6%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	10.8%
Rocky Mountains	CO,NV,UT,WY,NM	6.5%
West Coast	CA,WA	1.8%
Northern Great Plains	MT,ND,SD	10.5%

National Rig Depth Rating

The national rig depth rating schedule was calculated using a three year average based on the Smith Rig Count as reported by *Oil and Gas Journal*. Percentages are applied to determine the cumulative available rigs for drilling.

3. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's 2006 hydrocarbon resource assessment.[1]

- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2008. The production volumes are from the Minerals Management Service database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is determined in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on MMS's latest[1] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by the MMS is shown in Table 3-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomic to develop.

[1] U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S.OCS Oil and Natural Gas Resources*, February 2006.

Table 3-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting

Table 3-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, Oil and Gas Division

Determination of Discoveries

The number and size of discoveries is determined based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

Table 3-3. MMS Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Minerals Management Service

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \quad (3\text{-}1)$$

where,

TotalFields	=	Total number of fields by evaluation unit and field size class
CumNFW	=	Cumulative new field wildcats drilled in an evaluation unit
γ	=	search coefficient
EU	=	evaluation unit
iFSC	=	field size class.

The search coefficient (γ) was chosen to make the Equation 3-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates for a search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to provide enough data points to determine a reasonable fit to the discovery model. A polynomial was fit to all of

[2]Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

the relative search coefficients in the region. A polynomial was fit to the resulting search coefficients as follows:

$$\gamma_{\mathrm{EU,iFSC}} = \beta 1 * \mathrm{iFSC}^2 + \beta 2 * \mathrm{iFSC} + \beta 3 * \gamma_{\mathrm{EU,10}} \qquad (3\text{-}2)$$

where,

β1	=	0.243 for Western GOM and 0.0399 for Central and Eastern GOM
β2	=	-0.3525 for Western GOM and -0.6222 for Central and Eastern GOM
β3	=	2.3326 for Western GOM and 3.0477 for Central and Eastern GOM
iFSC	=	field size class
γ	=	search coefficient for field size class 10.

Cumulative new field wildcat drilling is determined by

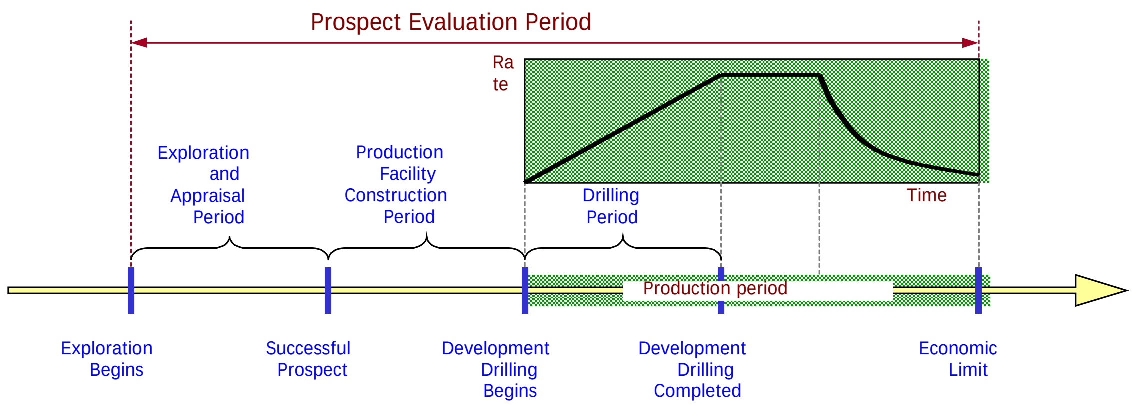
$$\mathrm{CumNFW}_{\mathrm{EU,t}} = \mathrm{CumNFW}_{\mathrm{EU,t-1}} + \alpha 1_{\mathrm{EU}} + \beta_{\mathrm{EU}} * (\mathrm{OILPRICE}_{\mathrm{t-nlag1}} * \mathrm{GASPRICE}_{\mathrm{t-nlag2}}) \qquad (3\text{-}3)$$

where,

OILPRICE	=	oil wellhead price
GASPRICE	=	natural gas wellhead price
α, β	=	estimated parameter
nlag1	=	number of years lagged for oil price
nlag2	=	number of years lagged for gas price
EU	=	evaluation unit

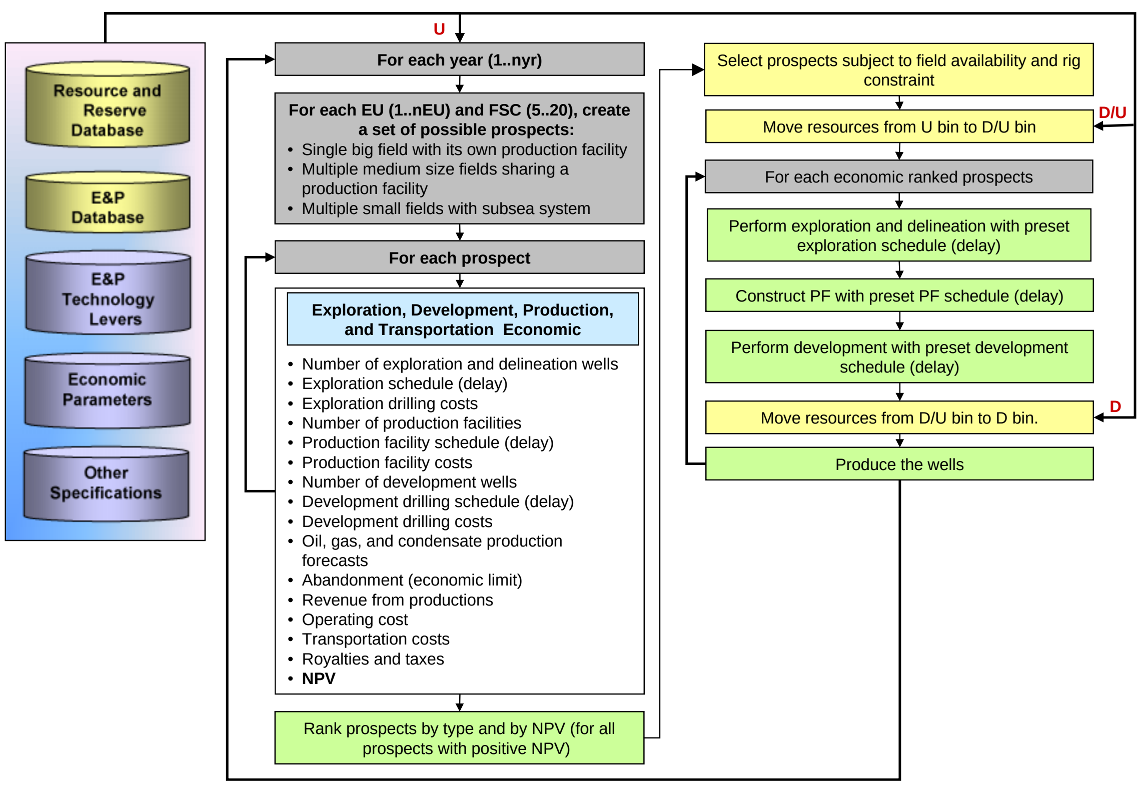
The decision for exploration and development of the discoveries determine from Equation 3-1 is performed at a prospect level that could have more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3-2.

Figure 3-1. Prospect Exploration, Development, and Production Schedule



Source: ICF Consulting

Figure 3-2. Flowchart for the Undiscovered Field Component of the OOGSS



Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/30 – 1)*0.4].

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts}(\$/\text{well}) = 2{,}000{,}000 + 5.0\text{E}-09 * \text{WD} * \text{DD}^3 \tag{3-4}$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\begin{aligned}\text{ExplorationDrillingCosts}(\$/\text{well}) &= 2{,}500{,}000 + 200 * (\text{WD} + \text{DD}) \\ &\quad + \text{WD} * (400 + 2.0\text{E-}05 * \text{DD}^2)\end{aligned} \tag{3-5}$$

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts}(\$/\text{well}) = 7{,}000{,}000 + 1.0\text{E}-05 * \text{WD} * \text{DD}^2 \tag{3-6}$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\text{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \text{SLT} + 1{,}500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2 \tag{3-7}$$

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform which is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the tower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells, however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \tag{3-8}$$

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (3{,}000{,}000 + 750 * (\text{WD} - 1{,}000)) \tag{3-9}$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \tag{3-10}$$

Spar Platform (SPAR). Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (3{,}000{,}000 + 500 * (\text{WD} - 1{,}000)) \tag{3-11}$$

Subsea Wells System (SS). Subsea systems range from single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \tag{3-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3-4.

Table 3-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$\begin{aligned} \text{DevelopmentDrillingCost}(\$ / \text{well}) = {} & 1{,}500{,}000 + (1{,}500 + 0.04 * DD) * WD \\ & + (0.035 * DD - 300) * DD \end{aligned} \tag{3-13}$$

For water depths greater tan 900 meters,

$$\begin{aligned} \text{DevelopmentDrillingCost}(\$ / \text{well}) = {} & 4{,}500{,}000 + (150 + 0.004 * DD) * WD \\ & + (0.035 * DD - 250) * DD \end{aligned} \tag{3-14}$$

where,

WD = water depth in feet
DD = drilling depth in feet.

Completion and Operating

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3-5.

Table 3-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001 - 20,000	> 20,000
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

Annual operating costs are determined by

$$\text{OperatingCost}(\$ / \text{structure} / \text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \tag{3-15}$$

Transportation

It is assumed in the model that existing trunk pipelines will be used, and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend upon the type of production technology used. The abandonment costs for fixed platforms and compliant towers assume the structure is abandoned. The costs for tension leg platforms, converted semi-submersibles, and converted tankers assume that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based upon historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical project development in the offshore consists of the following phases:[3]

- Exploration phase,
    - Exploration drilling program
    - Delineation drilling program
- Development phase,
- Fabrication and installation of the development/production platform
    - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
    - Construction of gathering system
- Production operations, and
- Field abandonment.

[3]The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one finds the field and three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends upon the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$\text{DevelopmentWells} = \frac{5}{\text{FSC}} * \text{FSIZE}^{\beta_{\text{DepthClass}}} \tag{3-16}$$

where,

FSC = field size class
FSIZE = resource volume

β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

Table 3-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	Water Depth (Feet)														
Number of Slots	**0**	**100**	**400**	**800**	**1000**	**1500**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**	**9000**	**10000**
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS								3	3	3	4	4	4	4	5

Source: ICF Consulting

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3-7.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

Table 3-7. Development Drilling Capacity by Production Facility Type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)	
Drilling Depth (feet)	**Drilling Capacity (24 slots)**
0	24
6000	24
7000	24
8000	20
9000	20
10000	20
11000	20
12000	16
13000	16
14000	12
15000	8
16000	4
17000	2
18000	2
19000	2
20000	2
30000	2

Maximum Number of Wells Drilled (wells/field/year)			
Water Depth (feet)	**SS**	**FPS**	**FPSO**
0	4		4
1000	4		4
2000	4		4
3000	4	4	4
4000	4	4	4
5000	3	3	3
6000	2	2	2
7000	2	2	2
8000	1	1	1
9000	1	1	1
10000	1	1	1

Source: ICF Consulting

Gas (plus lease condensate) production is calculated based on gas resource and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Field Abandonment

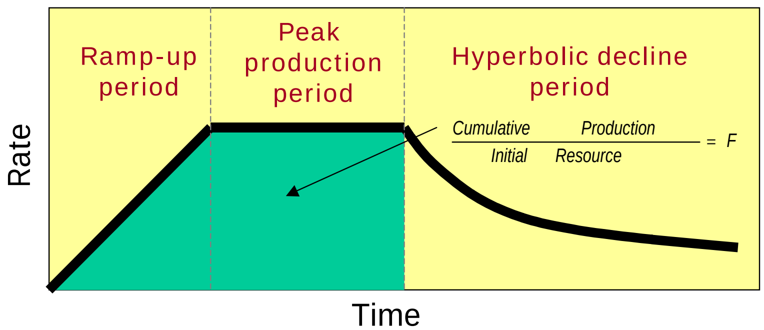
All wells in a field are assumed to be shut-in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource is for each field corresponds to the field size class as specified in Table 3-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3-13). The production profile is also the same as that of an undiscovered field (Figure 3-3).

Figure 3-3. Undiscovered Field Production Profile



Source: ICF Consulting

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2008 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field includes location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

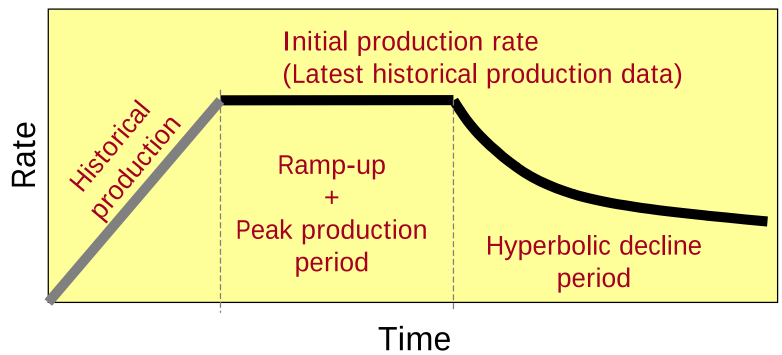
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3-5). Production will decline using a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3-9. Associated-dissolved gas and lease condensate production is determined the same way as in the undiscovered field component.

Table 3-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Great White	AC857	8717	2002	14	372	2010
Telemark	AT063	4457	2000	12	89	2010
Droshky	GC244	2900	2007	12	89	2010
Hornet	GC379	3878	2001	13	182	2010
GC448	GC448	3266	2008	12	89	2010
MC503	MC503	3099	2008	14	372	2010
Cascade	WR206	8143	2002	14	372	2010
Chinook	WR469	8831	2003	14	372	2010
Trident	AC903	9743	2001	13	182	2011
Ozona	GB515	3000	2008	12	89	2011
Knotty Head	GC512	3557	2005	15	691	2011
West Tonga	GC726	4674	2007	12	89	2011
Ringo	MC546	2460	2006	14	372	2011
Tubular Bells	MC725	4334	2003	12	89	2011
PONY	GC468	3497	2006	13	182	2012
Norman	GB434	5000	2006	15	691	2013
Puma	GC823	4129	2003	14	372	2013
Kaskida	KC292	5860	2006	15	691	2013
Big Foot	WR029	5235	2005	12	89	2013
St. Malo	WR678	7036	2003	14	372	2013
Jack	WR759	6963	2004	14	372	2013
Grand Cayman	GB517	5000	2006	13	182	2014
Kodiak	MC771	4986	2008	15	691	2015
Stones	WR508	9556	2005	12	89	2015
Entrada	GB782	4690	2000	14	372	2016
Freedom	MC948	6095	2008	15	691	2017
Julia	WR627	7087	2007	12	89	2017
Hal	WR848	7657	2008	12	89	2018
Tiber	KC102	4132	2009	16	1419	2019

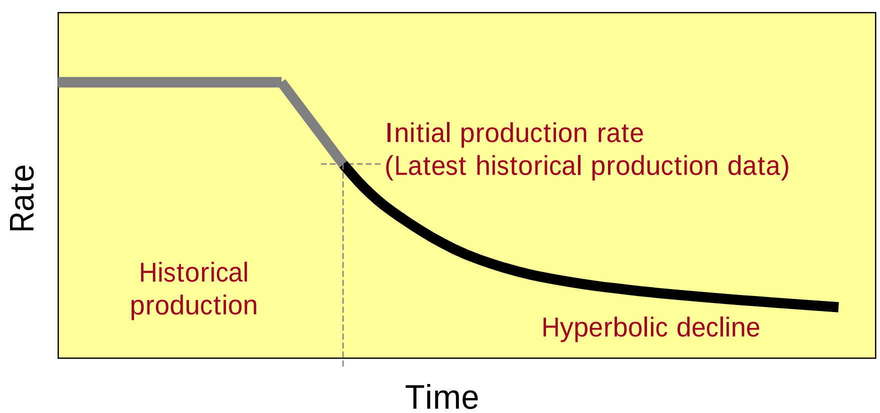
Source: Office of Integrated Analysis and Forecasting

Figure 3-4. Production Profile for Producing Fields - Constant Production Case



Source: ICF Consulting

Figure 3-5. Production Profile for Producing Fields - Declining Production Case



Source: ICF Consulting

Table 3-9. Production Profile Data for Oil & Gas Producing Fields

	Crude Oil						Natural Gas					
	FSC 2 - 10			FSC 11 - 17			FSC 2 - 10			FSC 11 - 17		
Region	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate
Shallow GOM	2	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in the given year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. In each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as:

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \quad (3\text{-}17)$$

where,

RESOFF	=	beginning- of-year reserves
PRDOFF	=	production
NRDOFF	=	new reserve discoveries
REVOFF	=	reserve extensions, revisions, and adjustments
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=nonassociated gas)
t	=	year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k} \right) \quad (3\text{-}18)$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k} \right) \quad (3\text{-}19)$$

where,

NRDOFF	=	new reserve discovery
NIRDOFF	=	new inferred reserve additions
NFDISC	=	new field discoveries
RSVGRO	=	reserves growth factor (8.2738 for oil and 5.9612 for gas)
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=gas)
t	=	year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, then the reserves need to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Reconfiguring Equation 3-1 to solve for REVOFF gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \qquad (3\text{-}20)$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base. Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3-10.

Table 3-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3.A. Offshore Data Inventory

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
DEVLCOST	DevelopmentDrilling Cost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingC osts	Exploration well drilling cost	$ per wells	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
INFRSVOFF	I	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)
KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions
NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental);

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
				4 Lower 48 offshore subregions
NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1
NIRDOFF	NIRDOFF	Offshore new inferred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions
OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
PRJOFF	N	Offshore project life	Years	Fuel (oil, gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
SC	Γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions
TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore
TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)
UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;
WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)
WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

PARAMETERS		
Parameter	Description	Value
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6

PARAMETERS		
Parameter	**Description**	**Value**
TOTFLD	Total number of evaluation units	3600
nANN	Total number of announce discoveries	127
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
ann_EU	Announced discoveries - Evaluation unit name	-	OIAF
ann_FAC	Announced discoveries - Type of production facility	-	MMS
ann_FN	Announced discoveries - Field name	-	OIAF
ann_FSC	Announced discoveries - Field size class	integer	MMS
ann_OG	Announced discoveries - fuel type	-	MMS
ann_PRDSTYR	Announced discoveries - Start year of production	integer	MMS
ann_WD	Announced discoveries - Water depth	feet	MMS
ann_WL	Announced discoveries - Number of wells	integer	MMS
ann_YRDISC	Announced discoveries - Year of discovery	integer	MMS
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	MMS
cstCap	Cost of capital	percent	MMS
dDpth	Drilling depth by PA, EU, FSC	feet	MMS
deprSch	Depreciation schedule (8 year schedule)	fraction	MMS
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	MMS
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	MMS

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	Wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	Wells/field/year	ICF
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	MMS
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	MMS
Drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	MMS
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	MMS
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	OIAF
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	OIAF
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	OIAF
levExpSucRate	Seismic technology (increase exploration success rate)	percent	OIAF
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	OIAF
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	OIAF
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	OIAF
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	OIAF
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	OIAF
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF
nDevWls	Maximum number of development wells by PA, EU, FSC	integer	ICF
nEU	Number of evaluation units in each PA	integer	ICF
nmEU	Names of evaluation units by PA	-	ICF
nmPA	Names of planning areas by PA	-	ICF

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
nmPF	Name of production facility and subsea-system by PF type index	-	ICF
nmReg	Names of regions by region	-	ICF
ndiroff	Additions to inferred reserves by region and fuel type	oil: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	MMS
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	MMS
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	MMS
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	MMS
prd_ID	Producing fields - MMS field ID	-	MMS
prd_OG	Producing fields - Fuel type	-	MMS
prd_YRDISC	Producing fields - Year of discovery	year	MMS
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	OIAF
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	MMS
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	MMS
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	MMS
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	Miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	MMS
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	MMS
vMean	Geometric mean MMBOE of FSC	MMBOE	MMS
vMin	Minimum MMBOE of FSC	MMBOE	MMS
wDpth	Water depth by PA, EU, FSC	feet	MMS
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF
Sources: MMS = Minerals Management Service; ICF = ICF Consulting; OIAF = EIA, Office of Integrating Analysis and Forecasting			

Appendix 3.B. Offshore Parameter Estimation

Offshore Gulf of Mexico Crude Oil

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE_t = a0 + a1 * LOILRES_t + a2 * LPOIL_t + a3 * LCRUDE(-1) + a4 * DUM \qquad (3.B\text{-}1)$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year oil reserves
LPOIL	=	natural log of the regional wellhead price of oil in 1987 dollars
LCRUDE(-1)	=	natural log of crude oil production in the previous year
DUM	=	a dummy variable that equals 1 for years after 1986 and 0 otherwise.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-6.48638	2.65947	-2.43897
LOILRES	.821851	.313405	2.62233
LPOIL	.115556	.051365	2.24969
LCRUDE(-1)	.974244	.137890	7.06538
DUM	.079112	.045683	1.73175

SAMPLE: 1978 to 1991
NUMBER OF OBSERVATIONS = 14

Dependent variable: LCRUDE
Mean of dependent variable = 5.65758
Std. dev. of dependent var. = .106897
Sum of squared residuals = .021640
Variance of residuals = .240446E-02
Std. error of regression = .049035
R-squared = .854325
Adjusted R-squared = .789581
Durbin-Watson statistic = 1.47269
Durbin's h = 1.04017
Durbin's h alternative = .725714
F-statistic (zero slopes) = 13.1954
Schwarz Bayes. Info. Crit. = -5.52974
Log of likelihood function = 25.4407

Pacific Offshore Crude Oil

Price elasticities were estimated using the AR1 procedure in TSP which corrects for first order serial correlation using a maximum likelihood iterative technique. The regression equation is given by:

$$\begin{aligned} LCRUDE_t &= a0 + a1 * LOILRES_t + a2 * LPOIL_t + \rho * LCRUDE_{t-1} \\ &\quad - \rho * (a0 + a1 * LOILRES_{t-1} + a2 * LPOIL_{t-1}) \end{aligned} \tag{3.B-2}$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year crude oil reserves
LPOIL	=	natural log of the regional wellhead price of crude oil in 1987 dollars
ρ	=	autocorrelation parameter
t	=	year.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	1.34325	.443323	3.02995
LOILRES	.310216	.067090	4.62390
LPOIL	.181190	.067391	2.68865
□	-.355962	.320266	-1.11146

SAMPLE: 1977 to 1991
NUMBER OF OBSERVATIONS = 15

Dependent variable: LCRUDE
(Statistics based on transformed data)
Mean of dependent variable = 5.31728
Std. dev. of dependent var. = .646106
Sum of squared residuals = .209786
Variance of residuals = .017482
Std. error of regression = .132220
R-squared = .971382
Adjusted R-squared = .966613
Durbin-Watson statistic = 1.61085
F-statistic (zero slopes) = 161.152
Log of likelihood function = 10.6711

(Statistics based on original data)
Mean of dependent variable = 4.001171
Std. dev. of dependent var. = .231415
Sum of squared residuals = .220359
Variance of residuals = .018363
Std. error of regression = .135511
R-squared = .711359
Adjusted R-squared = .663252
Durbin-Watson statistic = 1.61258

4. Alaska Oil and Gas Supply Submodule

This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil and gas production from the Onshore North Slope, Offshore North Slope, and Other Alaska (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Alaskan National Wildlife Refuge area in the east. This section provides an overview of the basic approach including a discussion of the discounted cash flow (DCF) method.

AOGSS Overview

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1).Transportation costs are used in conjunction with the relevant market price of oil or natural gas to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow (DCF) method is used to determine the economic viability of Alaskan drilling and production activities. Oil and gas investments decisions 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 multi-year projects, as well as the discovery of a new field is dependent on s profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, and historical production patterns and announced plans for currently producing fields.

Calculation of Costs

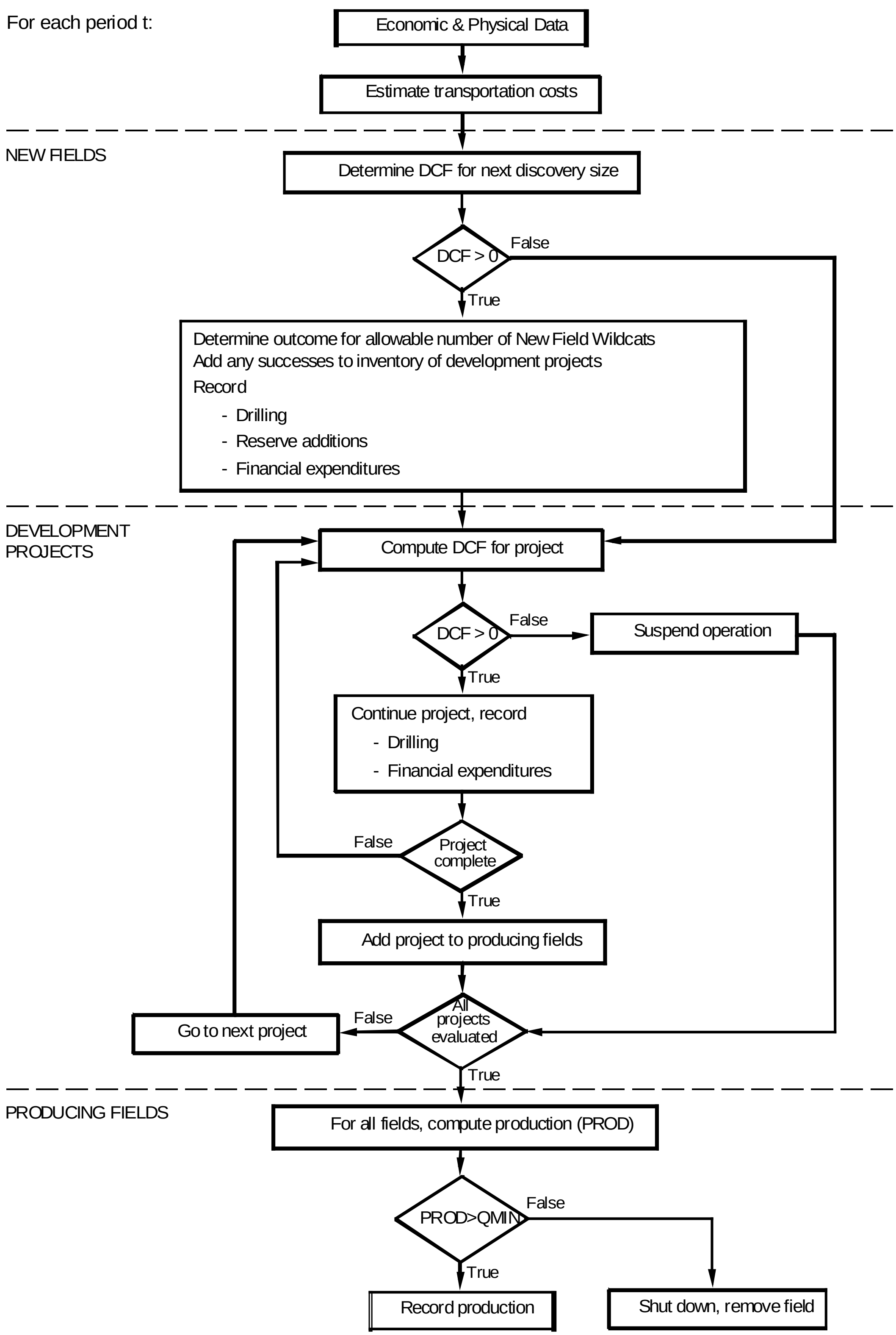
Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as:

- Drilling costs,
- Lease equipment costs, and
- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48, but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements that are included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation, and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \tag{4-1}$$

where,

i	=	well class (exploratory=1, developmental=2)
r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
DRILLCOST	=	drilling costs
T_b	=	base year of the forecast
TECH1	=	annual decline in drilling costs due to improved technology.

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once this equipment is moved up to Alaska, it is too expensive to transport back to the lower 48. Consequently, company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of limited number of drilling rigs and equipment available for use.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil or gas well is given by:

$$EQUIP_{r,k,t} = EQUIP_{r,k,t} * (1 - TECH2)^{r - T_b} \qquad (4\text{-}2)$$

where,

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
EQUIP	=	lease equipment costs
T_b	=	base year of the forecast
TECH2	=	annual decline in lease equipment costs due to improved technology.

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,t} * (1 - TECH2)^{r - T_b} \qquad (4\text{-}3)$$

where,

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2)
t	=	forecast year
OPCOST	=	operating cost
T_b	=	base year of the forecast
TECH3	=	annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil and gas producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.

- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.

- Operating costs are expensed.

- All remaining successful field development costs are capitalized.

- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil and gas projects.[1] A positive DCF is necessary to continue operations for a known field, whether exploration, development, or production. Selection of new prospects for initial exploration occurs on the basis of the profitability index which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the transportation cost to lower 48 markets. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs, while natural gas transportation costs are strictly pipeline costs (tariffs) to the lower 48. Transportation costs are specified for each field, based on the fuel type (i.e., oil or gas) and on the transportation cost of that fuel for that region. This cost directly affects the expected revenues from the production of a field as follows:[2]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \quad (4\text{-}4)$$

where,

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the lower 48 states

[1]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[2]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

TRANS	=	transportation cost.

The expected discounted cash flow associated with a representative oil or gas project in a field f at time t is given by:

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \tag{4-5}$$

where,

PVREV	=	present value of expected revenues
PVROY	=	present value of expected royalty payments
PVDRILLCOST	=	present value of all exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity
PVOPCOST	=	present value of operating costs
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes
PVWPT	=	present value of expected windfall profits tax[3]

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{4-6}$$

where,

PVEXPCOST	=	present value exploratory drilling costs
PVDEVCOST	=	present value developmental drilling costs
PVEQUIP	=	present value lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore equal to:

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}} \tag{4-7}$$

The field with the highest positive PROF in time t is then eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

[3]Since the Windfall Profits Tax was repealed in 1988, this variable would normally be set to zero. It is included in the DCF calculation for completeness.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into reserves requires a successful new field wildcat well. The discovery procedure can be determined endogenously or supplied at the option of the user. The procedure requires data regarding:

- the maximum number of new field wildcat wells drilled in any year,
- new field wildcat success rate, and
- any restrictions on the timing of drilling,
- technically recoverable oil and gas resource estimates by region,
- distribution of technically recoverable field sizes within each region.

The endogenous procedure generates:

- the set of individual fields to be discovered, specified with respect to size and location,
- an order for the discovery sequence, and
- a schedule for the discovery sequence.

The new field discovery procedure divides the estimate for technically recoverable oil and gas resources into a set of individual fields. The field size distribution data is obtained from U.S. Geological Survey estimates.[4] The field size distribution is used to determine a largest field size based on the volumetric estimate corresponding to an acceptable percentile of the distribution. The remaining fields within the set are specified such that the distribution of estimated sizes conforms to the characteristics of the input distribution. Thus, this estimated set of fields is consistent with the expected geology with respect to expected aggregate recovery and the relative frequency of field sizes.

New field wildcat drilling depends on the estimated expected DCF for the set of remaining undiscovered recoverable prospects. If the DCF for each prospect is not positive, no new drilling occurs. Positive DCF's motivate additional new field wildcat drilling. Drilling in each year matches the maximum number of new field wildcats. A discovery occurs as indicated by the success rate; for example, a success rate of 12.5 percent means that there is one discovery in each sequence of eight wells drilled. By assumption, the first new field well in each sequence is a success. The requisite number of dry holes must be drilled prior to the next successful discovery. Consequently, the number of exploratory wells drilled per year determines the number of years that pass between new discoveries.

[4] *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, USGS (1989); and *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*, USGS (April 2001); and *U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA)* USGS (2002).

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules would also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in Alaskan National Wildlife Refuge were permitted, then the earliest possible development date would be 2020.[5] Another example is the development of the West Sak field is expected to be delayed until technology can be developed that will enable the heavy crude oil of that field to be economically extracted.

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the drilling schedule is determined by the user or some set of specified rules. However, if the DCF for a given project is negative, then exploration and development of this project is suspended in the year in which this occurs. The DCF for each project is evaluated in subsequent years for a positive value; at which time, exploration and development will resume.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[6] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to peak rate,
- peak rate sustained for 3 to 8 years, and
- production rates decline by 5 to 18 percent per year, for known fields under development, after production declines below the peak rate; unknown fields decline by 10 percent per year.

The production algorithm build-up and peak-rate periods are based on the expected size of the undiscovered field, with larger fields having longer build-up and peak-rate periods than the smaller fields.

[5] The earliest ANWR field is assumed to go into production 10 years after the first projection year; so the first field comes on line in 2020 for the *Annual Energy Outlook 2010* projections. See also *Analysis of Crude Oil Production in the Arctic National Wildlife Refugee*, EIA, SR/OIAF/2008-03, (May 2008).

[6] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

The pace of development and the ultimate number of wells drilled for a particular field is based upon the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for any given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been discovered, but that have not begun production. These fields include, for example, a series of expansion fields in the Prudhoe Bay area, and a series of fields in the National Petroleum Reserve - Alaska (NPRA), and offshore fields. For these fields, the starting date of production and their production rate was not determined by the discovery process outlined above, but is based upon public announcements by the company(s) developing those fields.

Producing Fields

Oil production from fields producing as of the base year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on the most recently available field-specific production rates.

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[7] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the lower 48.[8] The Prudhoe Bay Field is the largest known deposit of North Slope gas (24.5 Tcf)[9] and currently all of the gas produced from this field is re-injected to maximize oil production. Total North Slope gas reserves equal 35.4 Tcf.[10] Furthermore, the undiscovered onshore central North Slope and NPRA natural gas resource base is estimated to be over 90 Tcf.[11] Collectively, these North Slope natural gas reserves and resources are more than enough to satisfy the 1.6 Tcf per year gas requirements of an Alaska gas pipeline well after the end of the *Annual Energy Outlook* projections. Consequently, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska gas pipeline during the *Annual Energy Outlook* projection period.

[7] Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[8] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[9] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[10] Ibid.

[11] *Economics of Undiscovered Oil and Gas in the North Slope of Alaska: Economic Update and Synthesis*, U.S. Geological Survey, Open-File Report 2009–1112, Table 1 mean estimate, page 6.

Appendix 4.A. Alaskan Data Inventory

Variable Name					
Code	Text	Description	Unit	Classification	Source
ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	NPC
ANGTSRES	--	ANGTS reserves	BCF	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	OIAF
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	OIAF
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OIAF
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	OIAF
DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OIAF
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	OIAF
FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	USGS
FSZCOAK	—	Alaska oil field size distributions	MMB	3 Alaska regions	USGS
FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	AOGCC
KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	OIAF
PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	OIAF
PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans
RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code

Variable Name		Description	Unit	Classification	Source
Code	Text				
RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	USGS
SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	USGS
SRAK	SR	Alaska drilling success rates	fraction	Alaska	OIAF
STTXAK	STRT	Alaska state tax rate	fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	fraction	Alaska	OIAF
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	OIAF
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code

Source: National Petroleum Council (NPC), Office of Integrated Analysis and Forecasting (OIAF), United States Geologic Survey (USGS), Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen, [12] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, the petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. One approach, which the majority of the oil companies pursued, mines the oil shale rock in underground mines, followed by surface facility retorting of the rock to create bitumen, which is then be further processed into syncrude. Occidental Petroleum Corp. pursed the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, while the remaining underground rock is "rubblized" using explosives to create large caverns filled with oil shale rock. The rubblized oil shale rock is then set on fire to cause the kerogen to convert into bitumen, with the bitumen being pumped to the surface for further processing into syncrude. The modified in-situ approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because the leaching of underground bitumen and other petroleum compounds might contaminate underground aquifers.

A completely in-situ oil shale process is undergoing experimental testing by Shell Oil Co., in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[13] are produced from separate production wells. The in-situ process has substantial environmental and cost benefits relative to the other 2 approaches. The environmental benefits are lower water usage, less surface disturbance, and an absence of oil shale waste piles on the surface that would leach petroleum liquids for an extended period of time. Other advantages of the in-situ process include: 1) access to deeper oil shale resources, 2) greater oil and gas per acre because the process uses the entire resource column and not just the richest portion of the resource column, and 3) direct production of petroleum products rather than a synthetic crude oil, which would require more refinery processing. Lower production costs are expected for the in-situ approach because massive volumes of rock would not be moved, and because the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Moreover, the in-situ process reduces the capital risk by building self-contained modular production units, which can then be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been fully demonstrated, there is already a substantial body of evidence from field testing conducted by Shell Oil Co. that the in-situ process is technologically feasible.[14] The current Shell field

[12] Kerogen is a solid organic compound, which is also found in coal.

[13] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.

[14] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

research program is expected to conclude around the 2014 through 2017 timeframe with the construction of a small scale demonstration plant expected to begin shortly thereafter. The Oil Shale Supply Submodule (OSSS) assumes that the first commercial size oil shale plant cannot be built prior to 2017.

Given the inherent cost and environmental benefits of the in-situ approach, a number of other companies, such as Chevron and ExxonMobil are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being explored, the large scale production of oil shale will have to rely on the in-situ approach. However, because in-situ oil shale projects have never been built, the cost and operational parameters of such in-situ facilities is unknown. Consequently, the Oil Shale Supply Submodule (OSSS) relies on the project parameters and costs associated with the underground mining and surface retorting approach that were designed during the 1970s and 1980s. In this context, the underground mining and surface retorting facility parameters and costs are meant to be a surrogate for the in-situ oil shale facility that is more likely to be built. Although the in-situ process is expected to result in a lower cost oil shale product, this lower cost is somewhat mitigated by the fact that the underground mining and surface retorting processes developed in the 1970s and 1980s did not envision the strict environmental regulations that prevail today, and therefore embody an environmental cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the higher expected cost structure of the underground mining/surface retorting facility sets a higher barrier to the initiation of oil shale project production, which should be viewed as a more conservative approach to the market penetration of in-situ oil projects. Public opposition to building any type of oil shale facility is likely to be great, irrespective of the fact that the in-situ process is expected to be more environmentally benign than the predecessor technologies; and therefore the cost of building an in-situ oil shale facility is likely to be much greater than would be determined strictly by the engineering parameters of such a facility.[15]

The Oil Shale Supply Submodule (OSSS) only represents economic decision making. In the absence of an existing large-scale oil shale projects, it was impossible to determine the potential environmental constraints and costs of implementing oil production on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on the in-situ technology, and infeasibility of large-scale implementation of the underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, it was assumed that only one new facility can begin construction in any specific future year, and as more facilities are built over time, the intervening time interval between each new facility declines to the point where one new facility can be built every year. The latter assumption is intended to mimic a technology penetration curve even though there is no informational basis for defining a more rigorously specified penetration rate. A full-scale oil shale production facility has never been constructed nor operated for an extended period of time. Although the Canadian oil sands industry development history might be viewed as an analogous situation, it would be misleading. The first commercial Canadian oil sands facility began operating in 1967 and it took over 30 years to develop into a rapidly growing industry. This slow penetration rate, however, was largely caused by low world oil prices from the mid-1980s

[15] Project delays due to public opposition can significantly increase project costs and reduce project rates of return.

through the 1990s and the lower cost of developing conventional crude oil supply.[16]

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of syncrude per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[17] Consequently, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2035.

Within the oil shale submodule, during each year of the projection, the submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's prevailing crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, then an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified within the submodule. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero, followed by whether the construction of a facility in that year is precluded by the construction constraints assumed within OSSS.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[18] The facility parameter values and cost estimates of the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to reflect the current cost environment.[19] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [20] because coal mining techniques and technology would be employed to mine oil shale

[16] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[17] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[18] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

[19] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[20] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost

rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 26 percent lower in 2035 relative to the initial 2004 cost structure.

Starting with the *Annual Energy Outlook 2009* projections, the Paraho oil shale facility capital cost was increased by 50 percent to reflect the higher energy facility costs resulting from higher commodity costs (e.g., steel). Under the revised oil shale facility cost assumption, oil shale production becomes profitable around $100 per barrel, absent any technological progress

Although the Paraho cost structure seem unrealistic relative to the notion that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, whereas there is no information whatsoever regarding the expected cost of the in-situ process. Moreover, even though the in-situ process is expected to be cheaper per barrel of output than the Parado process, this should be weighted against the fact that 1) oil and gas drilling costs have increased dramatically over the last 5 years, somewhat narrowing that cost difference, and 2) the Parado costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that an energy production project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volume of natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative facility costs assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, transported offsite, and priced at prevailing regional wellhead natural gas prices. Similarly, the electricity consumed on site is purchased from the local power grid at prevailing industrial prices. This means that both the natural gas and the electricity are valued in the Net Present Value of the cash flow calculations at their respective regional prices, which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[21] Moreover, this treatment of natural gas and electricity prices automatically takes into consideration any embedded carbon dioxide emission costs associated with a particular NEMS scenario.

Paraho Oil Shale Facility Configuration and Costs

The Paraho Oil Shale Project costs were reported in 1976 dollars, but these costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices,

---

represents Arch Coal's average western underground mining cost.

[21] This Colorado/Utah/Wyoming region enjoys relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) because the cost of existing electricity generation equipment is inherently lower than new generation equipment, because of the inflation and depreciation effects over time.

electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. The Paraho facility parameters are listed in Table 5-1, with the text in parentheses indicating the variable name in the submodule.

Table 5-1. OSSS Paraho Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	100,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	25 years[22]
Facility construction time	OS_PRJ_CONST	5 year
Surface facility capital costs	OS_PLANT_INVEST	$4.8 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$400 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value
Carbon Dioxide Emissions Rate	OS_CO2EMISS	300 metric tons per 100,000 bbl/day of production

The construction lead time for oil shale facilities is assumed to be 5 years, based on construction time estimates developed for the Paraho Project.[23] Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output. In an effort to mimic the fact that an in-situ oil shale process is most likely to be developed rather than underground mining and surface retorting process, the facility linearly ramps up production over a 5 year period (i.e., 20 percent per year).[24]

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2030, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

A Paraho oil shale facility produces natural gas and consumes electricity. The parameters provided below represent the level of annual gas production and annual electricity consumption

[22] The facility's operational period was extended from 20 years to 25 years for the AEO2009 projections to take into account the 5-year ramp-up to full production. A discussion of this and other parameter changes in the OSSS for the AEO2009 is discussed in an EIA/OIAF/OGD memorandum to Andy Kydes from Philip Budzik, entitled: "Oil Shale Project Size and Production Ramp-Up," dated November 16, 2007.

[23] An in-situ facility would also require about five years before initial production began. Ibid.

[24] Ibid.

for a 100,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[25]

Table 5-2. Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters and Their prices and Costs

Facility Parameters	OSSS Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	32.25 billion cubic feet per year
Wellhead gas sales price	OS_GAS_PRICE	Dollars per Mcf (2004 dollars)
Electricity consumption	OS_ELEC_CONSUMP	1.66 billion kilowatt-hours per year
Electricity consumption price	OS_ELEC_PRICE	Dollars per kilowatt-hour (2004 dollars)

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation, which is then discounted to a net present value. In those years in which the net present value exceeds zero, then a new oil shale facility can be constructed, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 30 year period, composed of 5 years for construction and 25 years for plant operations. During the first 5 years of the 30-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 5 years. In the sixth year, the plant goes into partial operation, and produces 20 percent of the rated output. So in the sixth year revenues and operating expenses are assumed to be 20 percent of their full-production values. In years 7, 8, and 9, the plant output increases an additional 20 percent per year, while operating expenses increase by the same proportion each year. In years 10 through 30, the plant operates at its maximum utilization rate. During years 10 through 30, total revenues equal oil revenues plus natural gas revenues.[26]

Oil revenues are calculated based on current year oil prices. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil at that time and is <u>not</u> based either on historical price trends or future expected prices. Oil revenues per plant are calculated as follows:

$$\begin{aligned} OIL\_REVENUE_t = & OIT\_WOP_t * (1.083/0.732) * OS\_PRJ\_SIZE \\ & * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-8}$$

where,

OIT_WOP_t	=	World oil price at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars

[25] Op. cit. Noyes Data Corporation.
[26] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 100,000 barrel per day oil shale syncrude facility.

OS_PROJ_PRJ_SIZE = Facility project size in barrels per day
OS_CAP_FACTOR = Facility capacity factor
365 = Days per year.

During year 10 through 30, natural gas revenues are calculated as follows:

$$GAS\_REVENUE_t = OS\_GAS\_PROD * OGPRCL48_t * (1.083/.732) * OS\_CAP\_FACTOR \quad (5\text{-}9)$$

where,

OS_GAS_PROD = Annual natural gas production for 100,000 barrel per day facility
$OGPRCL48_t$ = Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732)= GDP chain-type price deflators to convert 1987 dollars into 2004 dollars

OS_CAP_FACTOR = Facility capacity factor.

During year 10 through 30, electricity consumption costs are calculated as follows:

$$ELECT\_COST_t = OS\_ELEC\_CONSUMP * PELIN_t * (1.083/.732) * 0.003412 * OS\_CAP\_FACTOR \quad (5\text{-}10)$$

where,

OS_ELEC_CONSUMP = Annual electricity consumption for a 100,000 barrel per day facility

$PELIN_t$ = Electricity price in Colorado/Utah/Wyoming at time t
(1.083 / .732) = GNP chain-type price deflators to convert 1987 dollars into 2004 dollars

OS_CAP_FACTOR = Facility capacity factor.

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \quad (5\text{-}11)$$

where,

$$TOT\_REVENUE_t = \text{Total project revenues at time t}$$
$$TOT\_COST_t = \text{Total project costs at time t.}$$

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{5-12}$$

While total project costs are calculated as follows:

$$\begin{aligned} TOT\_COST_t = {} & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \tag{5-13}$$

where,

$$OS\_PLANT\_OPER\_CST = \text{Annual plant operating costs per year}$$
$$ROYALTY_t = \text{Annual royalty costs at time t}$$
$$PRJ\_MINE\_COST = \text{Annual plant mining costs}$$
$$ELEC\_COST_t = \text{Annual electricity costs at time t}$$
$$INVEST\ CO2\_COST_t = \text{Annual carbon dioxide emissions costs at time t}$$
$$INVEST_t = \text{Annual surface facility investment costs.}$$

While the plant is under construction (in years 1 through 5) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (in years 6 through 30), the capital costs (INVEST) are zero, while the other four cost elements take on positive values. The annual investment cost for the five years of construction assumes that the construction costs are evenly spread over the 5-year construction period and is calculated as follows:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{5-14}$$

Because the plant output is composed of both shale oil syncrude and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{5-15}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$\begin{aligned} PRJ\_MINE\_COST = {} & OS\_MINE\_CST\_TON * \frac{42}{OS\_GALLON\_TON * OS\_CONV\_EFF} \\ & * OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-16}$$

where,

42	=	gallons per barrel
365	=	days per year.

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as:

$$\begin{aligned} CASH\_FLOW_t = & \left(PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)\right) + \\ & (OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \end{aligned} \quad (5\text{-}17)$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

Table 5-3. Discount Rate Financial Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	70 percent
Facility equity beta	OS_EQUITY_VOL	1.75
Expected market risk premium	OS_EQUITY_PREMIUM	6.75 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is a project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. In 2005, a median beta for oil and gas field exploration service firms was 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.75.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.75 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in Ba range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$\begin{aligned} OS\_DISCOUNT\_RATE_t = & (((1 - OS\_EQUITY\_SHARE) * (MC\_RMCORPBAA_t / 100 + \\ & OS\_DEBT\_PREMIUM)) * (1 - OS\_CORP\_TAX\_RATE) + \\ & (OS\_EQUITY\_SHARE * ((OS\_EQUITY\_PREMIUM * \\ & OS\_EQUITY\_VOL) + MC\_RMGFCM\_10NS_t / 100)) \end{aligned} \tag{5-18}$$

where,

OS_EQUITY_SHARE	=	Equity share of total facility capital
$MC\_RMCORPBAA_t / 100$	=	BAA corporate bond rate
OS_DEBT_PREMIUM	=	Facility debt risk premium
OS_CORP_TAX_RATE	=	Corporate income tax rate
OS_EQUITY_PREMIUM	=	Expected market risk premium
OS_EQUITY_VOL	=	Facility equity volatility beta
$MC\_RMGFCM\_10NS_t / 100$	=	10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$OS\_DISCOUNT\_RATE_t = ((1.0 + OS\_DISCOUNT\_RATE_t) / (1.0 + INFL_t)) - 1.0 \tag{5-19}$$

where,

$INFL_t$ = Inflation rate at time t.

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE + OS\_PRJ\_CONST} \left[CASH\_FLOW_t * \left[\frac{1}{1 + OS\_DISCOUNT\_RATE_t} \right]^t \right] \tag{5-20}$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Construction Timing Constraints

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are two constraints to further oil shale facility construction. The first constraint on oil shale facility construction is imposed by the absence of a Federal land leasing program for commercial oil shale facilities. The second constraint on oil shale facility construction is the financial and technical risk of building a full-scale commercial oil shale syncrude production facility. The following discussion describes which of these two constraints determines the earliest possible date for a commercial oil shale facility within the OSSS. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market Penetration Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Maximum Oil Shale Production	OS_MAX_PROD	1 million barrels per year
Earliest Facility Construction Start Date	OS_START_YR	2017

The highest grade oil shale resources are located on Federal land located in Colorado, Utah, and Wyoming, where these three States meet. So, Federal land is the most desirable location for siting commercial oil shale facilities. The U.S. Department of Interior, Bureau of Land Management (BLM), however, must first implement a commercial oil shale facility leasing program before commercial oil shale syncrude facilities can be built on Federal land.[27] The OSSS assumes that a BLM leasing program, including the award of Federal oil shale leases will be accomplished by 2009, so that the first commercial plant could begin construction in 2010. This BLM leasing schedule assumes that between 2 to 3 years will be required to complete the final environmental impact statement and that an additional 1 to 2 years are required to complete the first oil shale land lease auction. Of course, if the draft environmental impact statement faces significant Court challenges, the completion of the first BLM auction could occur well after 2009. Although the BLM could have a commercial oil shale lands leasing program in place by 2010 or shortly thereafter, this leasing process is <u>not</u> the primary constraint to building the first commercial oil shale facility.

The binding constraint to first commercial production is the rate at which field testing can be conducted and concluded so as to reduce the technical and financial risks associated with oil shale production. In June of 2005, the BLM solicited requests for oil shale RD&D leases. Each oil shale RD&D lease nomination encompasses a 160-acre tract and associated preference rights to an additional contiguous area of 4,960 acres to be reserved for a preferential right to convert to a commercial lease at a future time after additional BLM review. In 2006 and 2007, the BLM awarded 4 RD&D leases with 3 in Colorado and 1 in Utah. Of the four leases, only one will employ small-scale surface retorting process using previously mined oil shale, while the other

[27] On June 9, 2005, BLM published a Federal Register notice (page 33753) soliciting nominations for oil shale research, development and demonstration leases.

three leases employ variations of the in-situ process approach.

Shell's oil shale RD&D program is considered to be the most advanced, having begun in 1997. Shell is also most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility sometime during the 2014 through 2017 timeframe. Consequently, the earliest likely initiation of a full-scale commercial plant would be 2017.[28]

New technology penetration is constrained by financial and technical risks. The financial risks are largely determined by the size of the investment (relative to the size of the corporation), the length of the construction period (with longer construction periods potentially resulting in significant market changes since construction began), and by the product's price volatility. The technical risks include: low production rates to due technology failures, equipment breakdowns, construction cost overruns, lower than expected production rates, etc. Because the risk of employing a new untested technology is considerably greater than that associated with well established technologies, industry participants often take a wait-and-see approach, in which they hope to learn from an early implementer's mistakes and improvements. Consequently, technology penetration is slow after the new technology first becomes available, followed by a subsequent acceleration of its penetration after the technology has been perfected and proven.

In order to mimic an initially slow market penetration, followed by increasing rate of penetration, the OSSS implements a technology penetration algorithm, which specifies that 5 years must pass since the first facility began construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility began construction. This technology penetration algorithm implicitly assumes that only a single oil shale plant can begin construction in any future year. In conjunction with the initial construction start year of 2017, the first oil shale facility would begin operation in 2023, with the second facility starting in 2027, and the third facility starting in 2030, and followed by one new facility every year thereafter.[29]

Because oil shale production is highly uncertain, not only from a technological and economic perspective, but also from an environmental perspective, an upper limit to oil shale production is assumed within the OSSS. The upper limit on oil shale production is 1 million barrels per day, which is equivalent to 10 facilities of 100,000 barrels per day, operating at full capacity or 11 facilities operating at 90 percent capacity. Because the market penetration algorithm does not permit the earliest plant construction to begin earlier than 2017, even under high, economically feasible oil prices, total oil shale production grows to be no greater than 380,000 barrels per day by 2035. So the upper limit on oil shale production is never reached during any of the NEMS runs.

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970's and early 1980's, the complete absence of any current commercial-scale oil shale

[28] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up," and based on public information and private conversations subsequent to the development of that memorandum.

[29] Alternatively, one can view the fact that OSSS assumes a large commercial plant size of 100,000 barrels per day to indicate the possibility that smaller oil shale facilities (e.g., 50,000 barrels per day) are initiated at a more rapid penetration rate.

production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970's, then the prospects for oil shale development remain weak through 2035. However, technological progress can totally alter the economic and environmental landscape in ways currently unanticipated. For example, if the Shell Oil in-situ process were to be demonstrated to be both technically and economically feasible, it would significantly improve the prospects for an oil shale industry, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

6. Foreign Natural Gas Supply Submodule

This section describes the structure for the Foreign Natural Gas Supply Submodule (FNGSS) within the Oil and Gas Supply Module (OGSM). Most of what was once contained in this submodule has now been transferred to the Natural Gas Transmission and Distribution Module (NGTDM) and is documented as such. The only piece that remains in OGSM is the representation of conventional natural gas, including from tight formations, in Western Canada. The model consists of estimated equations for new gas wells drilled, the amount found per well, and the expected production rate from the established proved reserves. This expected production rate is used as a basis for developing a supply curve for Western Canada for use in the market equilibration process in the NGTDM.

The approach taken to determine WCSB gas supplies differs from that used in the domestic submodules of the OGSM. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally an estimated extraction rate determines production potential [production to reserves ratio (PRR)]. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

Conventional Gas from the Western Canadian Sedimentary Basin

Wells Determination

The total number of successful conventional natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and proxy term for the drilling cost per well, as follows:

$$\begin{aligned} SUCWELL_t &= \exp(\beta 0) * CN\_PRC00^{\beta 1} * URRCAN^{\beta 2} \\ &\quad * CST\_PRXYLAG^{\beta 3} * \exp(\beta 4 * CURPRRCAN) \end{aligned} \quad (6\text{-}21)$$

where,

$$CURPRRCAN_t = OGPRDCAN_{t-1} / CURRESCAN \quad (6\text{-}22)$$

where,

$SUCWELL_t$ = total conventional successful gas wells completed in Western Canada in year t

CN_PRC00_t	=	price per Mcf of natural gas[30] in 2000 US dollars in year t
$URRCAN_t$	=	remaining conventional gas recoverable resources in year t in Western Canada in (Bcf), specified below
CST_PRXYLAG	=	proxy term to reflect the change in drilling costs per well, projected into the future based on projections for the average lower 48 drilling costs
CURPRRCAN	=	production-to-reserve ratio from last year
$OGPRDCAN_{t-1}$	=	conventional gas production in the previous forecast year (million cubic feet)
CURRESCAN	=	proved reserves of conventional gas at the beginning of the previous forecast year (million cubic feet)
β_0	=	econometrically estimated parameter (-1.85639, Appendix D)
β_1	=	econometrically estimated parameter (-1.09939, Appendix D)
β_2	=	econometrically estimated parameter (1.57373, Appendix D)
β_3	=	econometrically estimated parameter (-0.86063, Appendix D)
β_4	=	econometrically estimated parameter (33.6237, Appendix D)

The number of wells is restricted to increase by no more than 30 percent annually.

[30] In the fall of 2007 legislation was passed to increase the royalty rate in Alberta from 25 percent to 30 percent. Since royalty rates are not explicitly modeled for Canada, the effect of this was modeled by decreasing the price that would be seen in Alberta for the purposes of making drilling decisions by 0.9 (ROYADJ), which is equivalent to (1-.3)/(1-.25), starting in 2009 when the legislation takes affect.

Reserve Additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is, all else being constant, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption based, while the current version was econometrically estimated using the following:

$$FRCAN_t = \exp\{(1-\rho) * \beta 0\} * URRCAN_t^{\beta 1} * FRLAG^{\rho} * URRCAN_{t-1}^{-\rho * \beta 1}] \qquad (6\text{-}23)$$

where,

$FRCAN_t$	=	finding rate in year t (Bcf per well)
FRLAG	=	finding rate in year t-1 (Bcf per well)
$URRCAN_t$	=	remaining conventional gas recoverable resources in year t in Western Canada in (Bcf)
β_0	=	econometrically estimated parameter (-25.3204, Appendix D)
β_1	=	econometrically estimated parameter (2.13897, Appendix D)
ρ	=	serial correlation parameter (0.428588, Appendix D)

Remaining conventional plus tight gas recoverable resources are initialized in 2004 and set each year thereafter as follows:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN \qquad (6\text{-}24)$$

where,

$RESBASE$ = initial recoverable resources in 2004 (set at 92,000 Bcf)[31]
$RESTECH$ = assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (1.5 percent or 0.0015)
$CUMRCAN_t$ = cumulative reserves added since initial year of 2004 in Bcf

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{6-25}$$

where,

$RESADCAN_t$ = reserve additions in year t, in BCF
$FRCAN_{t-1}$ = finding rate in the previous year, in BCF per well
$SUCWELL_t$ = successful gas wells drilled in year t

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{6-26}$$

where,

$RESBOYCAN_{t+1}$ = beginning of year reserves for t+1 (end of year reserves for t), in BCF
$CURRESCAN_t$ = beginning of year reserves for t, in BCF
$RESADCAN_t$ = reserve additions in year t, in BCF
$OGPRDCAN_t$ = production in year t, in BCF
t = forecast year

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the expected production-to-reserve ratio for new wells are adjusted accordingly.

Gas Production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

[31]Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004. Adjusted downward slightly so as not to double count the potential tight gas contribution in the early years.

Conventional gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

$$PRRATCAN_t = \frac{e^{C+\beta 1*\ln SUCWELL_t+\beta 2*\ln FRCAN_t+\beta 3*RLYR}}{1+e^{C+\beta 1*onSUCWEL_t+\beta 2*onFRCAN_t+\beta 3*(RLYR-1)}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{\rho} * e^{-\rho*(C+\beta 1*\ln SUCWELL_{t-1}+\beta 2*\ln FRCAN_{t-1})} \qquad (6\text{-}27)$$

where,

$PRRATCAN_t$	=	expected production-to-reserve natural gas ratio in Western Canada for conventional and tight gas
$FRCAN_t$	=	finding rate in year t, in BCF per well
$SUCWELL_t$	=	successful gas wells drilled in year t
RLYR	=	calendar year
C	=	econometrically estimated constant term (-74.5150, Appendix D)
β_1	=	econometrically estimated parameter (0.115314, Appendix D)
β_2	=	econometrically estimated parameter (0.41412, Appendix D)
β_3	=	econometrically estimated parameter (0.035578, Appendix D)
ρ	=	serial correlation parameter (0.912281, Appendix D)

The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.7 to 0.12.

Appendix 6.A. Canadian Data Inventory

Variable Name					
Code	Text	Description	Unit	Classification	Source
CURPRRCAN	PR	Canadian 1989 P/R ratio	Fraction	Canada; Fuel (gas)	Derived using data from the Canadian Petroleum Association
FEDTXR	FDRT	U.S. federal tax rate	fraction	Canada	U.S. Tax Code
FLOWCAN	--	Canadian flow rates	bls, MCF per year	Canada; Fuel (oil, gas)	Not used. Office of Integrated Analysis and Forecasting
FRTECHCAN	FRTECH	Canada technology factor applied to finding rate	fraction	Canada	Office of Integrated Analysis and Forecasting
HISTFRCAN	--	Historical Canadian finding rate for gas	BCF per well	Canada	Office of Integrated Analysis and Forecasting
HISTPRRCAN	--	Canadian gas production to reserves ratio for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
HISTRESAD	--	Canadian gas reserves additions for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
HISTRESCAN	--	Canadian beginning of year gas reserves for historical years	BCF	Canada; Fuel (gas)	Canadian Petroleum Association
HISTWELCAN	--	Canadian gas wells drilled in historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
INFRT	--	Canadian inflation rate	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting
OGCNPPRD	--	Canadian price of oil and gas	oil: 87$s/B gas: 87$s/mcf	Canada	NGTDM
OGPNGIMP	--	Natural gas import price	87$s/mcf	US/Canadian & US/Mexican border crossings and LNG destination points	NGTDM
RESBASE	Q	Canadian recoverable resource estimate	BCF	Canada	Canadian Geological Survey
OGINIT_IMP XOGOUT_IMP OGOUT_MEX	OGQNGEXP	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM	OGINIT_IMP XOGOUT_IMP OGOUT_MEX

Appendix A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (e.g., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation A-1).

$$\begin{aligned} DCF_T = (&PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP \\ &- PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \end{aligned} \tag{A-1}$$

where,

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation A.1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

[1]The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$WACC = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \qquad \text{(A-2)}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by:

$$disc = \frac{(1+WACC)}{(1+\pi_e)} - 1 \qquad \text{(A-3)}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n}\left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+disc}\right]^{t-T}\right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ COPRD \text{ if secondary fuel} \end{cases} \qquad \text{(A-4)}$$

where,

k	=	fuel type (oil or natural gas)
t	=	time period
n	=	number of years in the evaluation period
disc	=	discount rate
Q	=	expected production volumes
P	=	expected net wellhead price
COPRD	=	co-product factor.[3]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

The present value of the total expected revenue generated from the representative project is:

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{A-5}$$

where,

$PVREV_{T,1}$	=	present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$	=	present value of expected revenues generated from the secondary fuel.

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to:

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{A-6}$$

where,

ROYRT	=	royalty rate, expressed as a fraction of gross revenues.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by:

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{A-7}$$

where,

PRODTAX	=	production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs), and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period.)

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor,

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. The present value of expected drilling costs is given by:

$$\begin{aligned}PVDRILLCOST_T = \sum_{t=T}^{T+n} \Bigg[\Big[& COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_t \\ & + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \\ & + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \Big] * \left(\frac{1}{1 + disc} \right)^{t-T} \Bigg]\end{aligned} \qquad \text{(A-8)}$$

where,

COSTEXP	=	drilling cost for a successful exploratory well
SR	=	success rate (1=exploratory, 2=developmental)
COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for a oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells.

The present value of expected lease equipment cost is

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_t * (SR_1 * NUMEXP_t + SR_2 * NUMDEV_t) * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \qquad \text{(A-9)}$$

where,

EQUIP	=	lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as:

$$PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \qquad \text{(A-10)}$$

where,

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n}\left[OPCOST_t * \sum_{k=1}^{t}\left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k\right] * \left(\frac{1}{1+disc}\right)^{t-T}\right] \quad \text{(A-11)}$$

where,

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n}\left[COSTABN_t * \left[\frac{1}{1+disc}\right]^{t-T}\right] \quad \text{(A-12)}$$

where,

COSTABN = abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are

[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include:

- Windfall Profits Tax on oil was repealed,
- Investment Tax Credits were eliminated, and
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$\begin{aligned}\mathrm{PVTAXBASE_T} = \sum_{t=T}^{T+n} \Big[\big(&\mathrm{TREV_t - ROY_t - PRODTAX_t - OPCOST_t - ABANDON_t - XIDC_t} \\ &\mathrm{- AIDC_t - DEPREC_t - DHC_t}\big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{\mathrm{t-T}} \Big]\end{aligned} \qquad \text{(A-13)}$$

where,

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

$\mathrm{TREV_t}$, $\mathrm{ROY_t}$, $\mathrm{PRODTAX_t}$, $\mathrm{OPCOST_t}$, and $\mathrm{ABANDON_t}$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for purpose of determining corporate income tax liability at the State and Federal level.

[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included.

Table A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's **5-year SLM**[d] 20 percent of IDC's	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC's
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; first 1,000 barrels per day depletable under percentage depletion.
[c]Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d]Straight Line Method.

Expected expensed IDC's are defined as follows:

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t \\ & + COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \quad \text{(A-14)}$$

where,

COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. These costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year, referred to as the 5-year Straight Line Method (SLM) with half year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, then costs are recovered using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by:

$$\begin{aligned} AIDC_t = \sum_{j=\beta}^{t} \Big[& \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \\ & + COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \\ & * DEPIDC_t * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Big], \end{aligned} \tag{A-15}$$

$$\beta = \begin{cases} T \ \text{ for } t \le T + m - 1 \\ t - m + 1 \ \text{ for } \ t > T + m - 1 \end{cases}$$

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t ≤ n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[8]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad \text{(A-16)}$$

where,

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in

Table A-2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

Table A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$
\begin{aligned}
\mathrm{DEPREC}_t = \sum_{j=\beta}^{t} \Big[& \big[(\mathrm{COSTEXP}_T * \mathrm{EXKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_1 * \mathrm{NUMEXP}_j \\
& + (\mathrm{COSTDEV}_T * \mathrm{DVKAP} + \mathrm{EQUIP}_T) * \mathrm{SR}_2 * \mathrm{NUMDEV}_j + \mathrm{KAP}_j \big] \\
& * \mathrm{DEP}_{t-j+1} * \left(\frac{1}{1+\mathrm{infl}} \right)^{t-j} * \left(\frac{1}{1+\mathrm{disc}} \right)^{t-j} \Big],
\end{aligned} \tag{A-17}
$$

$$
\beta = \begin{cases} \mathrm{T} \ \text{ for } t \le \mathrm{T} + m - 1 \\ t - m + 1 \ \text{ for } \ t > \mathrm{T} + m - 1 \end{cases}
$$

where,

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for $t \le n+T-m$, MACRS with half year convention; otherwise, $1/(n+T-t)$ in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$
\mathrm{PVSIT}_T = \mathrm{PVTAXBASE}_T * \mathrm{STRT} \tag{A-18}
$$

where,

PVTAXBASE	=	present value of expected taxable income (Equation A.14)
STRT	=	state income tax rate.

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

The present value of expected federal corporate income tax is calculated using the following equation:

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{A-19}$$

where,

FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

Appendix B. Bibliography

Aerospace Corporation. 1976. *Alaska Natural Gas Transportation Systems Economic and Risk Analysis*.

Advanced Resources International: "Naturally Fractured Tight Gas Reservoir Detection Optimization", Quarterly Status Report for US DOE - METC, Contract number DE-AC21-93MC30086, May 23, 1997.

Allied Technology Group, Inc. 1996. "Model Quality Audit Report: Final Report - Oil and Gas Supply Module."

American Petroleum Institute. 1990-2005. *Joint Association Survey on Drilling Costs*, Finance, Accounting, and Statistics Department, Washington D.C.

Argonne National Laboratory, Environmental Assessment and Information Sciences Division. June 7, 1991 (revised draft). *National Energy Strategy Environmental Analysis Model (NESEAM): Documentation and Findings*, prepared for the DOE Office of Policy, Planning, and Analysis under contract W-31-109-Eng-38.

Arps, J.J. and T.G. Roberts. 1958. "Economics of Drilling for Cretaceous Oil on East Flank of Denver-Julesburg Basin," *Bulletin of American Association of Petroleum Geologists*, Vol. 42, No. 11 (November) pp. 2549-2567.

Attanasi, E.D., L.J. Drew, and D.H. Root. 1981. "Physical Variables and the Petroleum Discovery Process" in James Ramsey, ed., *The Economics of Exploration for Energy Resources* (Greenwich: JAI Press).

Attanasi, E.D. and Haynes, J.L. 1983. "*Future Supply of Oil and Gas from the Gulf of Mexico*", U.S. Geological Survey Professional Paper 1294, U.S. Geological Survey.

Bacigalupi, Suzan M., et al. October 1996. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1995*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Bailey, Ralph E. and Curtis, L.B. June 1984. *Enhanced Oil Recovery*, National Petroleum Council report Submitted to the Secretary of Energy, National Petroleum Council, Washington D.C.

Baker, R.A., Gehman, H.M., James, W.R., and White, D.A. 1984. "Geologic Field Number and Size Assessments of Oil and Gas Plays," *The American Association of Petroleum Geologists Bulletin*, Vol 68, No. 4, pages 426-437.

Beach, C. and MacKimnon, J. 1978. "A Maximum Likelihood Procedure for Regression with Autocorrelated Errors," *Econometrica,* Vol. 46, pages 51-58.

BehrenBruch, Peter. January 1995. *Deepwater Drilling & Production: Floating Production Facilities Key to Lower Cost Deepwater Development*, HP Petroleum, Oil and Gas Journal.

Beltramo, M., Manne a., Weyant J., *The Energy Journal*, 7 (July 1986), pp.15-32.

Bird, K.J. 1986. "A Comparison of the Play Analysis Techniques as Applies in Hydrocarbon Resource Assessments of the National Petroleum Reserve in Alaska and the Arctic National Wildlife Refuge," in Rice, D.D., ed., *Oil and Gas Assessment, Methods and Applications, American Association of Petroleum Geologists Studies in Geology*, No. 21, Tulsa.

Bourgoyne Jr., A.T., et al. 1991. *Applied Drilling Engineering*, Society of Petroleum Engineers (SPE) Textbook Series, Vol. 2, Second Printing, Society of Petroleum Engineers, Richardson, Texas.

Cazalet, E.G. 1977. *Generalized Equilibrium Modeling: The Methodology of the SRI-Gulf Energy Model*, Decision Focus Incorporated, Palo Alto, CA and Stanford Research Institute, Menlo Park, CA.

Chapman, L. Randy, et al. November 1995. *Platform/Pipeline Construction: Containing Field Abandonment Costs in the Gulf of Mexico*, Oil and Gas Journal.

Cherniavsky, E.A., and Juang, L.L. October 1979. *Resource Submodels of the Long-Range Energy Analysis Program: Documentation*, Report to the Division of Long-range Analysis, U.S. Energy Information Administration, Washington.

Cherniavsky, E.A. May 1982. "Oil/Gas Supply Modeling Considerations in Long-range Forecasting," in Gass, S.I., *Oil and Gas Supply Modeling, Proceedings of a Symposium held at the Department of Commerce, Washington, D.C., June 18-20, 1980*, U.S. Department of Commerce, NBS Special Publication 631.

Cox, J., and Wright, A. 1976. "The Determinants of Investment in Petroleum Reserves and Their Implications for Public Policy," *American Economic Review*, Vol. 66, No. 1, pages 153-167.

Cranswick, Deborah and Regg, James. February 1997. *Deepwater in the Gulf of Mexico: America's New Frontier*, OCS Report MMS 97 -0004, U.S. Minerals Management Service, New Orleans.

Davis, J.C., and Harbaugh, J.W. 1981. "A Simulation Model for Oil Exploration Policy on Federal Lands of the U.S. Outer Continental Shelf," in Ramsey, J., ed., *The Economics of Exploration for Energy Resources*, JAI Press, Greenwich.

Deacon, R., et al. 1983. *The Proposed California Crude Oil Severance Tax: An Economic Analysis*, The Economics Group, Inc., Santa Barbara.

Department of Revenue, State of Alaska. 1989, 1990, and 1991. *Petroleum Production Revenue Forecast*. Alaska.

Drew, L.J., Schuenemeyer, J.H., and Bawiec, W.J. 1982. *Estimation of the Future Rate of Oil and Gas Discovery in the Gulf of Mexico*, U.S. Geologic Survey Professional Paper, No. 252, Reston, VA.

DRI/McGraw-Hill, *Energy Review: Natural Gas Market Focus*, Standard & Poor's Corporation, Lexington, Massachusetts, 1990.

Dutton, Shirley P., Clift, Sigrid J., Hamilton, Douglas S., Hamlin, H. Scott, Hantzs, Tucker F., Howard, William E., Akhter, M. Saleem, Laubach, Stephen E.: "Major Low-Permeability-Sandstone Gas Reservoirs in the Continental United States" Bureau of Economic Geology - University of Texas and Gas Research Institute, 1993.

Eckbo, P.L., Jacoby, H.D., and Smith, J.L. 1978. "Oil Supply Forecasting: A Disaggregated Process Approach," *Bell Journal of Economics*, Vol. 9, No. 1, pages 218-235.

Energy and Environmental Analysis Inc., *Costs for LNG Imports Into the United States*, prepared for Gas Research Institute, GRI Contract #5087-800-1474, August 1988.

Energy and Environmental Analysis Inc. 1991. "Import and Supplemental Gas Supply," prepared for the Source and Supply Task Group of the National Petroleum Council Natural Gas Study.

U.S. Energy Information Administration: Annual Energy Outlook 2006 - With Projections to 2030", U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, February, 2006.

U.S. Energy Information Administration: "US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves - Annual Reports", U.S. Energy Information Administration, Office of Oil and Gas, U.S. Department of Energy, December, 1996-2004.

Energy Research Associates, *The Reemergence of LNG - A Global Perspective, Volume I*, 1989.

Epple, D. 1975. *Petroleum Discoveries and Government Policy: An Econometric Study of Supply*, Ballinger Publishing Company, Cambridge, Mass.

Epple, D. 1985. "The Econometrics of Exhaustible Resource Supply: A Theory and an Application," in Sargent, T.J., ed., *Energy Foresight and Strategy*, Resources for the Future, Washington.

Erickson, E.W., and Spann, R.M. 1971. "Supply Response in a Regulated Industry: The Case of Natural Gas," *The Bell Journal of Economics and Management Science*, Vol. 2, No. 1, pages 94-121.

Erickson, E.W., Millsaps, S.W., and Spann, R.M. 1974. "Oil Supply and Tax Incentives," *Brookings Papers on Economic Activity*, Vol. 2, pages 449-493.

Executive Office of the President. 1977. Decision and Report to Congress on the Alaska Natural Gas Transportation System. Energy Policy and Planning.

Eyssell, J.H. "The Supply Response of Crude Petroleum: New and Optimistic Results," *Business Economics*, Vol. 13, No. 3, pages 15-28.

Farmer, Richard D., Harris, Carl M., Murphy, Frederic H., and Damuth, Robert J. 1984. "The Outer continental Shelf Oil and gas Supply model of the U.S. Energy Information Administration," *North-Holland European Journal Of Operation Research*, 18.

Fisher, F.M. 1964. *Supply and Costs in the United States Petroleum Industry*, Johns Hopkins University Press for Resources for the Futures, Baltimore.

Fisher, W.L., *et al*, 1988, *An Assessment of the Natural Gas Resource Base of the United States*, Bureau of Economic Geology, University of Texas at Austin, Austin, Texas.

Gas Research Institute, *Baseline Projection Data Book: The 1989 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Strategic Planning and Analysis Division, Washington, DC, 1990.

Frantz, Joe: "Technology Applications Improve Antrim Shale Well Recoveries and Economics", GRI Gas Tips, Gas Research Institute, Winter, 1995/1996, p.5-11.

Gas Research Institute: “Advanced Stimulation Technology: Success in the Anadarko Basin”, GRI Gas Tips, Gas Research Institute, Baseline / Gas Resource Analytical Center, August, 1996.

Gas Research Institute: “Baseline Projection Data Book - 1998 Edition of the GRI Baseline Projection of US Energy Supply and Demand to 2015", Gas Research Institute, Baseline / Gas Resource Analytical Center, 1997.

Gas Research Institute: “Baseline Projection Data Book - 1997 Edition of the GRI Baseline Projection of US Energy Supply and Demand to 2015", Gas Research Institute, Baseline / Gas Resource Analytical Center, 1996.

Gas Research Institute: “GRI Baseline Projection of US Energy Supply and Demand - 1997 Edition, “The Contribution of Technology,”, Gas Research Institute, Baseline / Gas Resource Analytical Center, August, 1996.

Gas Research Institute, "The Long-Term Trends in U.S. Gas Supply and Prices: The 1989 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010," as published in *Gas Research Insights*, Strategic Planning and Analysis Division, Washington, DC, 1990.

Gas Research Institute (GRI). 1990. *Guide to the Hydrocarbon Supply Model*, prepared for the Gas Research Institute by Energy and Environmental Analysis, Inc., Washington, DC.

Goerold, W.T. 1987. Environmental and Petroleum Resource Conflicts: *A Simulation Model to Determine the Benefits of Petroleum Production in the Arctic National Wildlife Refuge, Alaska*. Materials and Society II(3).

Goerold, W.T. 1988. *A Simulation Model to Determine the Probability of Finding Economically Producible Petroleum in the Arctic National Wildlife Refuge, Alaska*, Proceedings Tenth Annual North American Conference. International Association for Energy Economics. Houston TX.

Grecco, M.G. April 1987. *Deepwater Development Economics*. Offshore Technology Conference.

Griffin, James M., and Moroney, John R., *Texas Severance Tax Model - The Economic Impact of Severance Taxes: Results from an Econometric Model of the Texas Oil and Gas Industry*, 1985. Report to the Texas Mid Continent Oil and Gas Association.

Haines, Leslie. July 1996. *Going Deep: Startling New Technologies and High Flow Rates Make the Deepwater Gulf of Mexico a World Class Frontier Play - and Our Last Best Hope*, Oil and Gas Investor.

Hansen, J.J. and Kornbrath, R.W. 1986. *Resource Appraisal Simulation for Petroleum in the Arctic National Wildlife Refuge, Alaska*. State of Alaska, Department of Natural Resources, Division of Geological and Geophysical Surveys, Professional Report 90.

Harkrider, John D., Middlebrook, Mike L., Aud, William W., Marrer, Kenneth D., Teer, George A.: “Advanced Stimulation Technology: Success in the Anadarko Basin”, GRI Gas Tips, Gas Research Institute, Spring, 1996, p.24-29.

Helfat, Constance E. September 1989. *Investment in Offshore Oil by Diversified Petroleum Companies*, Journal of Industrial Economics, Volume XXXVIII.

Hendricks, K., Novales, A. 1987. *Estimation of Dynamic Investment Functions in Oil Exploration*, Draft Manuscript.

Herron, E. Hunter. June 1982. *Unconventional-Gas Production Model*, Final Report prepared for the Brookhaven National Laboratory Associated Universities, Inc. by Gruy Federal Inc.

Huntington, H.G., Schuler, Glen E., et al., "North American Natural Gas Markets," *Energy Modeling Forum Stanford University*, February 1989.

Huntington, H.G., Schuler, Glen E., et al., "North American Natural Gas Markets: Selected Technical Studies," *Energy Modeling Forum Stanford University*, April 1989.

Huntington, H.G., Lyon, Thomas P., "Responses To Modeler Questionnaires, EMF 9: North American Natural Gas Markets," *Energy Modeling Forum Stanford University*, May 1987.

ICF-Lewin Energy, Inc. June 1998. *A Model for the Economic Analysis of U.S. Undiscovered Crude Oil Resources in the Lower-48 Offshore*, Prepared for U.S. Department of Energy Under Contract No. DE-AC01-85FE60603.

ICF Resources Incorporated. August 1995. *Primary Recovery Predictive Model for Total Oil Recovery Information System (TORIS)*.

ICF Resources Incorporated. January 1997. *Model Development for the Gas Systems Analysis Model: Draft Topical Report*, Prepared for Federal Energy Technology Center, U.S. Department of Energy, Task 4, DE-AC21-92MC28138.

ICF Resources Incorporated. January 1997. *Internal Survey of Deepwater Offshore Gulf of Mexico Projects Slated for Development, Based on Data Gathered from Various Industry Sources*.

ICF Resources Incorporated. July 1990. *Update and Analysis of Offshore Oil and Gas Exploration, Development, Production and Transportation Costs*, Submitted to U.S. Minerals Management Service Under Contract No. 14-12-0001-30424.

ICF Resources Incorporated. June 1994. *Update of the Regional Cost Functions for the TORIS Predictive Models*, Prepared for BDM-Oklahoma, Inc. Under Contract No. DE-AC22-94PC91008.

International Petroleum Encyclopedia, PennWell Publishing Co., Tulsa, OK, 1989.

Johnson, D. 1985. *Comparison of Alternatives for Deepwater Development in the Gulf of Mexico*, SPE Paper 13779 presented at the Hydrocarbon Economics and Evaluation Symposium, Dallas, Texas, March 14-15.

Johnson, Ronald C., Finn, Thomas M., Crovelli, Robert A., and Balay, Richard H.: “An Assessment of In-Place Gas Resources in Low-Permeability Upper Cretaceous and Lower Tertiary Sandstone Reservoirs, Wind River Basin, Wyoming”, US Geological Survey Open-File Report 96-264, Us Geological Survey, 1996.

Kalter, R.J., Tyner, W.E., and Hughes, D.W. 1975. *Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf*, Cornell University, Department of Agricultural Economics, A.E.RES. 75-33, Ithaca, N.Y.

Kaufman, G.M., and Barouch, E. 1978. "The Interface Between Geostatistical Modeling of Oil and Gas Discovery and Economics," *Mathematical Geology*, 10(5).

Kaufman, G.M., Runggaldier, W., and Livne, Z. 1981. "Predicting the Time Rate of Supply from a Petroleum Play," in Ramsey, J., ed., *The Economics of Exploration for Energy Resources*, JAI Press, Greenwich.

Khazzoom, D.J. "The FPC Staff's Econometric Model of Natural Gas Supply in the United States," *The Bell Journal of Economics and Managements Science*, Vol. 2, No. 1, pages 51-93.

Khodaverdian, Mohamad, McLennan, John, Palmer, Ian, Vaziri, Hans: "Coalbed Cavity Completion Analysis Suggests Improvements", GRI Gas Tips, Gas Research Institute, Winter, 1995/1996, p.22-29.

Kibbee, Stephen. June 1996. *"TLP Technology: SeaStar Minimal Platform For Small Deepwater Reserves"*, Atlantia Corporation, Oil and Gas Journal.

Kuuskraa, Vello A., Boyer, Charles M. III: "Economic and Parametric Analysis of Coalbed Methane", Hydrocarbons from Coal — AAPG Studies in Geology number38, 1993, p.373-394.

Le Blanc, Leonard. December 1995. *FORECAST'96: Operators Moving Into Era of Just-In-Time Production*, Oil and Gas Journal.

Lerch, Chris, et al. February 1997. *Ram-Powell Partners See Big Picture With Integrated Modeling*, The American Oil and Gas Reporter, Shell Offshore.

LNG Digest, Volume 15, Number 11, "News Briefs," Energy Research Associates, New York, November 1989.

Lore, Gary L., et al. August 1996. *Summary of the 1995 Assessment of the Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf: As of January 1, 1995*, U.S. Minerals Management Service, New Orleans.

Luneau, Barbara: "Accelerating Technology Development in the Greater Green River Basin", GRI Gas Tips, Gas Research Institute, Fall, 1995, p.4-10.

MacAvoy, P.W. and Pindyck, R.S. "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *The Bell Journal of Economics and Management Science*, Vol. 4, No. 2, pages 454-498.

MacDonald, John J. and Smith, Robert S. February 1997. *Offshore Topsides: Decision Trees Aid Production Facility Design*, Oil and Gas Journal.

Mansvelt Beck, F.W., and Wiig, K.M. 1977. *The Economics of Offshore Oil and Gas Supplies*, Lexington Books, Lexington, Mass.

Megill, R.E. 1988. *Exploration Economics*.

Melancon, J. Michael, et al. January 1997. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections from 1996 through 2000*, OCS Report MMS 97-0006, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. October 1990. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1989*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. October 1991. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1990*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. September 1992. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1991*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. August 1993. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1992*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. August 1994. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1993*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Melancon, J. Michael, et al. August 1995. *Outer Continental Shelf: Estimated Oil and Gas Reserves, Gulf of Mexico, December 31, 1994*, Resource Evaluation Office, U.S. Minerals Management Service, New Orleans.

Miers, John H. January 20, 1997. *The Gulf of Mexico's Revival: Technology Gives Gulf Prospects World-Class Investment Appeal*, Amoco Exploration & Production Co., Houston, Oil and Gas Journal.

Moritis, Guntis. April 20, 1992. "EOR Increases 24% Worldwide; Claims 10% of U.S. production" [Biennial EOR Production Report], *Oil and Gas Journal*, page 51 and following.

Moritis, Guntis. June 29, 1992. "More Enhanced Oil Recovery Project Information Obtained," *Oil and Gas Journal*, page 70 and following pages.

Murphy, Frederic H. and William Trapmann. 1982. "An Evaluation of the Alaskan Hydrocarbon Supply Model," *Oil and Gas Supply Modeling*, published by the National Bureau of Standards. Washington, DC.

National Energy Board, *Canada's Conventional Natural Gas Resources: A Status Report, ,* Canada, April 2004.

National Petroleum Council. 1981. *U.S. Arctic Oil and Gas*. Energy and Environmental Analysis, Inc. Arlington, VA.

National Petroleum Council. December 1980. *Unconventional Gas Sources*, Vols 1-4.

National Petroleum Council. 1984. *Enhanced Oil Recovery*, Washington, D.C.

National Petroleum Council. 1991. *Field Development Assumptions and Costs in the Hydrocarbon Supply Model*, Energy and Environmental Analysis, Inc., Arlington, VA.

National Petroleum Council. December 1999. *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, Washington, DC.

National Petroleum Council. 1992. *The Potential for Natural Gas in the United States*, Washington, DC.

National Research Council. 1992. *The National Energy Modeling System*, Committee on the National Energy Modeling System, Washington, DC.

Natural Gas Week, "DOE OKs Gas Import/Export with Mexico," June 12, 1989

Nesbitt, D., and Phillips, R. September 1980. *Financial Statements and Producer Behavior in Generalized Equilibrium Models Such as LEAP*, Decision Focus Incorporated Report.

Nesbitt, D.M. 1988. *Methodology of the GRI North American Regional Gas Supply-Demand Model, Appendix A*, Decision Focus Incorporated, Los Altos, CA.

Nesbitt, D.M. 1991. *Insights from the North American Regional Gas (NARG) Supply-Demand Model*, Presentation to the Imports and Alaska Working Group of the National Petroleum Council Natural Gas Study.

Newendorp, Paul, D. 1975. *Decision Analysis for Petroleum Exploration,* The Petroleum Publishing Company, Tulsa, OK.

Offshore Data Services, Inc. June 1997. *Database of Wells Drilled in the Deepwater Gulf of Mexico*, Houston, Texas .

Offshore Special Report. May 1997. *How Offshore Drilling Units Evolved*, Offshore Magazine, Pennwell Publications.

The Oil Daily Co., “Spot Prices on Interstate Pipeline Systems”, Natural Gas Week, 1996-1997.

Pautz, James F., et al. 1992. *Enhanced Oil Recovery Projects Data Base*, NIPER-583, National Institute for Petroleum and Energy Research, Bartlesville, Oklahoma.

Petroleum Economist, Volume LVI, Number 12, "Gas Set for 1990s Growth," Euromoney Publications pic, London, UK, December 1989.

Petroleum Economist, Volume LVI, Number 12, "Liquefied Natural Gas: Continued Market Expansion," Euromoney Publications pic, London, UK, December 1989.

Petroleum Information/Dwights LLC: “Production Data for the Rocky Mountain, Gulf Coast/Offshore, and Texas/Midcontinent Areas”, Petroleum Information/Dwights LLC (CD-ROM), March 1997.

Petroleum Intelligence Weekly, Special Supplement Issue, "World LNG Trade Entering New Growth Phase," Petroleum & Energy Intelligence Weekly, Inc., November 13, 1989.

Platt's Oilgram News, Volume 68, Number 54, "MARAD Rebuff's Cabot's $45-Million Attempt to Buy 3 LNG Tankers at Center of Dispute," McGraw-Hill, New York, March 19, 1990.

Platt's Oilgram News, Volume 68, Number 201, "LNG Ship Deal Jeopardized by New Lawsuit," McGraw-Hill, New York, October 16, 1990.

Potential Gas Agency: “Potential Supply of Natural Gas in the United States - Report of the Potential Gas Committee (December 31, 1996)”, Potential Gas Agency, March 1997.

Potential Gas Committee. 1988a. *Potential Supply of Natural Gas in the United States*, Potential Gas Agency, Colorado School of Mines, Golden, Colorado.

Powell, Stephen G. September 1990. *Arctic National Wildlife Refuge - How Much Oil Can We Expect?*. Resources Policy.

Powell, Stephen G. 1990. *A Risk Analysis of Oil Development in the Arctic National Wildlife Refuge*. The Energy Journal, Volume 12, Number 3.

Prato, A.A., and Miller, R.R. 1981. "Evaluating the Energy Production Potential of the United States Outer Continental Shelf," *Land Economics*, Vol. 57, No. 1, pages 77-90.

Riva, Joseph P., Jr. November 19, 1992. *The Domestic Oil Status and a Projection of Future Production*, CRS Report for Congress, 92-826 SPR, Congressional Research Service, Washington, D.C.

Riva, Joseph P., Jr. October 5, 1992. *Domestic Oil Production*, CRS Issue Brief, Order Code IB87068, Congressional Research Service, Washington, D.C.

Roy, K.J. 1975. "Hydrocarbon Assessment Using Subjective Probability and Monte Carlo Methods," in *First IIASA Conference on Methods and Models for Assessing Energy Resources Conference*, Honolulu.

Roy, K.J., Procter, R.M., and McCrossam, R.G. 1975. "Hydrocarbon Assessment Using Subjective Probability," in Davis, J.C., Doveton, J.H., and Harbaugh, J.W., conveners, *Probability Methods in Oil Exploration: American Association of Petroleum Geologists Research Symposium Notes*, Stanford, University, pages 56-60.

Samuelson, P., "Spatial Price Equilibrium and Linear Programming," *American Economic Review*, 42, 1952.

Stermole, Franklin J. and Stermole, John M. 1993. *Economic Evaluation and Investment Decision Methods*, Eighth Edition, Investment Evaluations Corporation, Golden, Colorado.

Trapmann, William. 1991. "Relating Natural Gas Resource Estimates to the Outlook for the Market," paper presented at the 14th Annual International Conference of the International Association for Energy Economists.

Tyler, Roger, Kaiser, W.R., Scott, A.R., Hamilton, D.S., Ambrose, W.A.: "Geologic and Hydrologic Assessment of Natural Gas from Coal: Greater Green River, Piceance, Powder River, and Raton Basins", Bureau of Economic Geology - University of Texas and Gas Research Institute, Contract number 5091-214-2261, 1995.

U.S. Congress. Office of Technology Assessment. 1989. *Oil Production in the Arctic National Wildlife Refuge: The Technology and the Alaskan Oil Context*. OTA-E-394. Washington, D.C.

U.S. Department of Energy. July 1994. *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations: 1990 through 199"*, Technical Report DOE/EIA-TR-0568, U.S. Energy Information Administration, Washington D.C.

U.S. Department of Energy: "GASIS Gas Information System - A National Database of Geological, Engineering, Production and Ultimate Recovery Data for U.S. Oil and Natural Gas Reservoirs", Department of Energy, GASIS Release 1 CD-ROM, March 1997.

U.S. Department of Energy. May 1997. *The National Energy Modeling System: An Overview*, DOE/EIA-0581, U.S. Energy Information Administration.

U.S. Department of Energy. 1978. *Midterm Oil and Gas Supply Modeling System Methodology Description*, DOE/EIA-0103/17 U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. December 1982. *Outer Continental Shelf (OCS) Oil and Gas Supply Model, Volume 1, Model Summary and Methodology Description*, DOE/EIA-0372/1 U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1982. *Outer Continental Shelf (OCS) Oil and Gas Supply Model*, *Volume 1, Model Summary and Methodology Description*, DOE/EIA-0372/1, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy, *The Petroleum Resources of Mexico*, DOE/EIA-0423, U.S. Energy Information Administration, Washington, DC, 1983.

U.S. Department of Energy. 1991. *Recommended Design for the National Energy Modeling System*, U.S. Energy Information Administration, NEMS Project Office, Washington, DC.

U.S. Department of Energy. 1986. *An Economic Analysis of Natural Gas Resources and Supply*, DOE/EIA-0481, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1987. *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge*. SR/RNGD/87-01. U.S. Energy Information Administration. Washington, DC.

U.S. Department of Energy, 1988, *An Assessment of the Natural Gas Resource Base of the United States*, DOE/W/31109-H1, Office of Policy, Planning & Analysis, Washington, DC.

U.S. Department of Energy, *International Energy Annual 1988*, DOE/EIA-0219(88), U.S. Energy Information Administration, Washington, DC, 1988a.

U.S. Department of Energy, *Natural Gas Annual 1988*, DOE/EIA-0131(88), U.S. Energy Information Administration, Washington, DC, 1988a.

U.S. Department of Energy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector; Technical Report Three: Methanol Production and Transportation Costs*, DOE/PE-0093 Office of Policy Planning and Analysis, November 1989.

U.S. Department Of Energy. 1989. *Abandonment Rates of the Known Domestic Oil Resource*, DOE/BC--89/6/SP, Bartlesville Project Office, Bartlesville, Oklahoma.

U.S. Department of Energy. 1989. *An Examination of Domestic Natural Gas Resource Estimates*, SR/RNGD/89-01, U.S. U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1989. *Federal Oil Research: A Strategy for Maximizing the Producibility of Known U.S. Oil*, DOE/FE-0139, Office of Fossil Energy, Washington, D.C.

U.S. Department of Energy. 1989a. *Annual Energy Review*, DOE/EIA-0384(89), U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1990. *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*, SR/NES/90-05, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1990. *United States Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. DOE/EIA-0216(90). U.S. Energy Information Administration. Washington, DC.

U.S. Department of Energy, *Development Costs of Undeveloped Non-associated Gas Reserves in Selected Countries*, Office of Policy Planning and Analysis, 1990.

U.S. Department of Energy, *Quarterly Sales and Prices Report*, Office of Fossil Energy, Office of Fuels Programs, various issues, 1990.

U.S. Department of Energy. 1990a. *United States Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90), U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. May 1991. *Intermediate Future Forecasting System: Executive Summary*, DOE/EIA-M023(91) U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1991. *Alaska Oil and Gas Energy Wealth or Vanishing Opportunity?*. DOE/ID/01570-H1. Office of Fossil Energy. Washington, DC.

U.S. Department of Energy. 1991. *The Outlook for Natural Gas Imports: Supporting Analysis for the National Energy Strategy*, SR/NES/90-06, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. April 1992. *Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model*, U.S. Energy Information Administration, Office of Oil and Gas, Washington, DC.

U.S. Department of Energy. 2008. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1994. *Documentation of the Oil and Gas Supply Module (OGSM), Appendix: Model Developers Report*, U.S. Energy Information Administration, Washington, DC.

U.S. Department of Energy. 1992. Component Design Report - *Basic Framework & Onshore Lower 48 Conventional Oil and Gas Supply*. U.S. Energy Information Administration. Washington, DC.

U.S. Department of Energy. 1992. *Model Methodology and Data Description of the Production of Onshore Lower 48 Oil and Gas Model*, Draft Report, U.S. Energy Information Administration, Washington, DC.

U.S. Department of the Interior, 1981, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, United States Geological Survey Circular 860, United States Geological Survey, Reston, Virginia.

U.S. Department of the Interior, 1987, *Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size*, PT-87-015-3120-985, Bureau of Land Management, Division of Mineral Resources, Alaska State Office.

U.S. Department of the Interior, 1988, *National Assessment of Undiscovered Conventional Oil and Gas Resources*, USGS-MMS Working Paper, Open File Report 88-373, United States Geological Survey and Minerals Management Service, Reston, Virginia.

U.S. Department of the Interior, 1989, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, United States Geological Survey and Minerals Management Service, Denver, Colorado.

U.S. Department of the Interior, *Federal Offshore Statistics 1990,* Minerals Management Service (MMS).

U.S. Department of the Interior, *Estimates of Undiscovered, Economically Recoverable Oil & Gas Resources: for the Outer Continental Shelf, Revised as of January 199*5 Minerals Management Service.

U.S. Department of the Interior, February 2006, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources,* Energy Policy Act of 2005, Minerals Management Service.

U.S. Department of the Interior, *Estimates of Undiscovered, Economically Recoverable Oil & Gas Resources: for the Outer Continental Shelf, Revised as of January 1999* Minerals Management Service.

U.S. Minerals Management Service. April 1996. *Deepwater Royalty Relief for New Leases: Interim Rule*, 30 CFR Part 260, RIN 1010-AC14, Offshore Minerals Analysis Division.

U.S. Minerals Management Service World Wide Web Page. February 1997. *"Database of 899 Producing Oil and Gas Fields in the Gulf of Mexico Outer Continental Shelf".*

Van Meter, John E. May 1995. *Production Technology: Deciding When To Use A MOPU For Field Development*, Paragon Engineering Services, Oil and Gas Journal.

Van Poollen, H.K. and Associates, Inc. 1978. *Documentation of Input Variables: Northern Alaska Hydrocarbon Model*.

Walls, M.A. 1989. *Forecasting Oil Market Behavior: Rational Expectations Analysis of Price Shocks*, Resources for the Future Discussion Paper EM87-03. Washington.

Walls, Margaret A. October 1990. *Analyzing the Determinants of Offshore Oil and Gas Supply: A Factual and Methodological Assessment*, Final Report Prepared for the Reserves and Natural Gas Division of the U.S. Energy Information Administration under ORNL Subcontract No. 90X-SE635V.

Walls, Margaret A. 1990. *A Survey of Oil and Gas Supply Models,* Draft Report, Resources for the Future, Washington, DC.

Wheatley, Richard. January 20, 1997. *Deepwater, Subsalt Prospects Open New Era for Gulf of Mexico Action*, Oil & Gas Journal.

White, D.A., and Gehman, H.M. 1979. "Methods of Estimating Oil and Gas Resources," *The American Association of Petroleum Geologists Bulletin*, Vol. 63, pages 2183-2192.

White, D.A. 1980. "Assessing Oil and Gas Plays in Facies-Cycle Wedges," *The American Association of Petroleum Geologists Bulletin*, Vol 64, pages 1158-1178.

White, D.A. 1981. "A Play Approach to Hydrocarbon Resource Assessment and Evaluation," in Ramsey, J., ed., *The Economics of Exploration for Energy Resources*, JAI Press, Greenwich.

Williams, M.R. and Atkins, P.A. April 1987. *Simple Subsea Trees for Shallow Water: An Economical Alternative*, Offshore Technology Conference.

Young, J.S. and Hauser, W.S. 1986. *Economics of Oil and Gas for ANWR for the Determination of Minimum Economic Field Size*. Bureau of Land Management. Division of Mineral Resource. Alaska State Office.

Appendix C. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the U.S. Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   2009

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2008. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2009

11. Energy Systems Described
    The OGSM projects oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves and development determines the rate of production from the stock of known reserves.

    The OGSM also projects natural gas trade via pipeline with Canada. U.S. natural gas trade with Canada is represented by seven entry/exit points.

12. Coverage
    Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    Time Units/Frequency: Annually 1990 through 2035
    Product(s): Crude oil and natural gas
    Economic Sector(s): Oil and gas field production activities and Canadian natural gas trade

13. Model Features
    Model Structure: Modular, containing six major components
    - Lower 48 Onshore Supply Submodule
    - Unconventional Gas Recovery Supply Submodule
    - Offshore Oil and Gas Supply Submodule
    - Foreign Natural Gas Supply Submodule
    - Alaska Oil and Gas Supply Submodule
    - Oil Shale Supply Submodule

    Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are determined by the discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
    Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
    - Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
    - Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
    - Alaska Operating cost - U.S. Geological Survey
    - Basin Differential Prices - Natural Gas Week, Washington, DC
    - State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
    - Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2007)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
    - Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report*, Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2007)*, DOE/EIA-0815(80-06)
    - Onshore Operating Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2007)*, DOE/EIA-0815(80-06)
    - Emissions Factors – U.S. Energy Information Administration
    - Oil and Gas Well Initial Flow Rates – U.S. Energy Information Administration, Office of Oil and Gas
    - Wells Drilled – U.S. Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well – U.S. Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves – U.S. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2008), DOE/EIA-0216(77-08)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: Unknown
    - Estimated Run Time: 287 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts
    Not applicable

19. Bibliography
    See Appendix B of this document.

Appendix D. Output Inventory

Variable Name	Description	Unit	Classification	Passed To Module
OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGCCAPPRD	Coalbed Methane production from CCAP		17 OGSM/NGTDM regions	NGTDM
OGCOPRD	Crude production by oil category	MMbbl/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMbbl/day	Shallow and deep water regions	Industrial
OGCOWHP	Crude wellhead price by oil category	87$/bbl	10 OGSM reporting regions	Industrial
OGCNQPRD	Canadian production of oil and gas	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGCNPPRD	Canadian price of oil and gas	oil:87$/ bbl gas:87$/ BCF	Fuel (oil, gas)	NGTDM
OGCORSV	Crude reserves by oil category	Bbbl	5 crude production categories	Industrial
OGCRDSHR	Crude oil shares by OGSM region and crude type	percent	7 OLOGSS regions	PMM
OGDNGPRD	Dry gas production	BCF	57 Lower 48 onshore & 6 Lower 48 offshore districts	PMM
OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGEORFTDRL	Total footage drilled from CO2 projects	feet	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORINJWLS	Number of injector wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORNEWWLS	Number of new wells drilled from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRD	EOR production from CO2 projects	Mbbl	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRDWLS	Number of producing wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEOYAD	Unproved Associated-Dissolved gas resources	TCF	6 Lower 48 onshore regions	Industrial
OGEOYRSVON	Lower 48 Onshore proved reserves by gas category	TCF	6 Lower 48 onshore regions 5 gas categories	Industrial
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial

Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSV	Proved Crude oil and natural gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYUGR	Technically recoverable unconventional gas resources	TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGGROWFAC	Factor to reflect expected future cons growth		NA	NGTDM
OGJOBS			NA	Macro
OGNGLAK	Natural Gas Liquids from Alaska	Mbbl/day	NA	PMM
OGNGPRD	Natural Gas production by gas category	TCF	10 OGSM reporting regions	Industrial
OGNGPRDGOM	Gulf of Mexico Natural Gas production	TCF	Shallow and deep water regions	Industrial
OGNGRSV	Natural gas reserves by gas category	TCF	12 oil and gas categories	Industrial
OGNGWHP	Natural gas wellhead price by gas category	87$/MCF	10 OGSM reporting regions	Industrial
OGNOWELL	Wells completed	wells	NA	Industrial
OGPCRWHP	Crude average wellhead price	87$/bbl	NA	Industrial
OGPNGEXP	NG export price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPNGWHP	Natural gas average wellhead price	87$/MCF	NA	Industrial
OGPPNGIMP	NG import price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGTDM
OGPRCOAK	Alaskan crude oil production	Mbbl	3 Alaska regions	NGTDM
OGPRDADOF	Offshore AD gas production	BCF	3 Lower 48 offshore regions	NGTDM
OGPRDADON	Onshore AD gas production	BCF	17 OGSM/NGTDM regions	NGTDM
OGPRDUGR	Lower 48 unconventional natural gas production	BCF	6 Lower 48 regions and 3 unconventional gas types	NGTDM
OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGQCRREP	Crude production by oil category	MMbbl	5 crude production categories	PMM
OGQCRRSV	Crude reserves	Bbbl	NA	Industrial
OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM

Variable Name	Description	Unit	Classification	Passed To Module
OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGQNGREP	Natural gas production by gas category	TCF	12 oil and gas categories	NGTDM
OGQNGRSV	Natural gas reserves	TCF	NA	Industrial
OGRADNGOF	Non Associated dry gas reserve additions, offshore	BCF	3 Lower 48 offshore regions	NGTDM
OGRADNGON	Non Associated dry gas reserve additions, onshore	BCF	17 OGSM/NGTDM regions	NGTDM
OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM
OGSHALENG	Gas produced	BCF	NA	NGTDM
OGTAXPREM	Canadian tax premium	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGTECHON	Technology factors	BCF	3 cost categories, 6 fuel types	Industrial
OGWPTDM	Natural Gas wellhead price	87$/MCF	17 OGSM/NGTDM regions	NGTDM