Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2023

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Update Information

The Oil and Gas Supply Module (OGSM) of the National Energy Modeling System (NEMS) model documentation reflects changes made to the OGSM over the past couple of years for the *Annual Energy Outlook* (AEO). The major revisions to the previous version of documentation include the following:

Updated onshore Lower 48 technology assumptions (Table 2-6)
Updated assumptions for the announced/nonproducing offshore discoveries (Table 3-8)
Updated assumptions for the Canadian Natural Gas Supply Submodule based on the Canada Energy Regulator (CER) report, *Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050*
Updated model representative contact information

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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. We prepare this report under our legal obligation to provide adequate documentation in support of our 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 the National Energy Modeling System (NEMS) by the OGSM. The 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. The OGSM projects U.S. oil and natural gas supply for seven Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on projected profitability to determine exploratory and developmental drilling levels for each region and fuel type.

OGSM also provides Canada's projected natural gas production (excluding production used to support Canada's liquefied natural gas [LNG] exports) to the Natural Gas Market Module (NGMM) and is used in determining Canada's imports to the United States as a result of the North American market equilibration that occurs in the NGMM. LNG imports into Canada also are determined in the NGMM. Canada's natural gas production is represented for two regions—Western Canada and Eastern Canada.

The OGSM uses both exogenous input data and data from other modules within NEMS. The primary exogenous inputs are resource levels, costs, production profiles, and tax rates—all of which are critical determinants of the expected returns from projected drilling activities. The NGMM provides regional projections of natural gas wellhead prices and production. Projections of the crude oil wellhead prices at the OGSM regional level come from the Liquid Fuels Market Model (LFMM). Important economic factors, namely interest rates and gross domestic product (GDP) deflators, flow to the OGSM from the Macroeconomic Activity Module (MAM). Controlling information (for example, projection year) and expectations information (for example, expected price paths) comes from the Integrating Module (in other words, the system module).

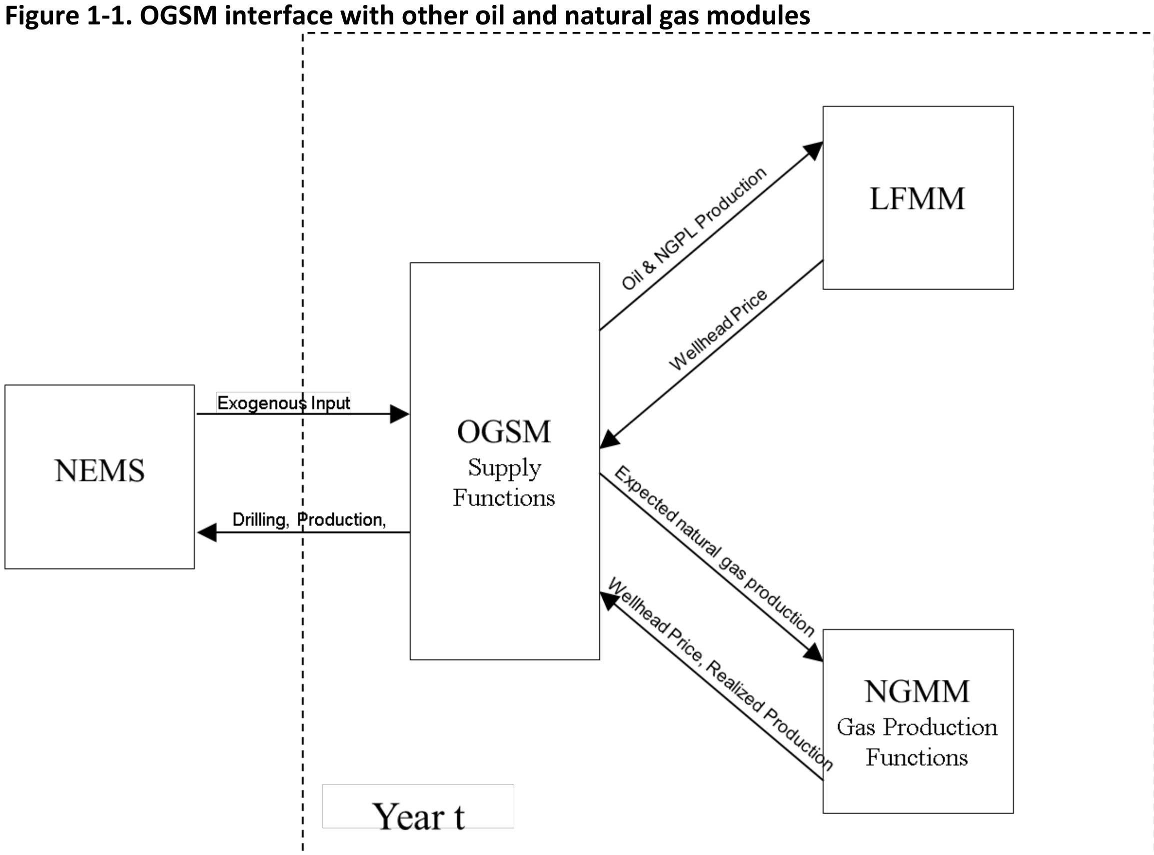
Outputs from the OGSM go to other oil and gas modules (NGMM and LFMM) and to other modules of NEMS. To equilibrate supply and demand in the given year, the NGMM employs short-term supply functions (with the parameters provided by the OGSM) to determine nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions, which reflect potential oil or natural gas flows to the market for a one-year period. The NGMM uses the natural gas functions, and the LFMM uses the oil volumes to determine equilibrium prices and quantities of crude oil and natural gas at the wellhead. The OGSM also provides projections of natural gas plant liquids production to the LFMM. Other NEMS modules receive projections of selected OGSM variables for various uses. Domestic oil and natural gas production is passed to the Integrating Module for reporting purposes. Projections of oil and natural gas production are also provided to the MAM to assist in projecting aggregate measures of output.

Model purpose

The OGSM is a comprehensive framework used to analyze oil and natural gas supply potential and related issues. Primarily, it projects domestic crude oil and natural gas production in response to price data received endogenously (within NEMS) from the NGMM and LFMM. Projected natural gas and crude oil wellhead prices are determined within the NGMM and LFMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides expected natural gas production to the NGMM for use in its short-term domestic nonassociated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGMM determines nonassociated gas production.

Figure 1-1. OGSM interface with other oil and natural gas modules



The OGSM provides domestic crude oil production to the LFMM. The interaction of supply and demand in the LFMM determines the level of imports. System control information (for example, projection year) and expectations (for example, expected 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 natural gas supply outlook of the OGSM.

The 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 is divided into 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: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

The OGSM provides mid-term (currently through year 2050) projections and serves as an analytical tool to assess alternative supply policies. One publication that uses OGSM projections 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 and 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
- The rate of penetration for different technologies into the industry by fuel type

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

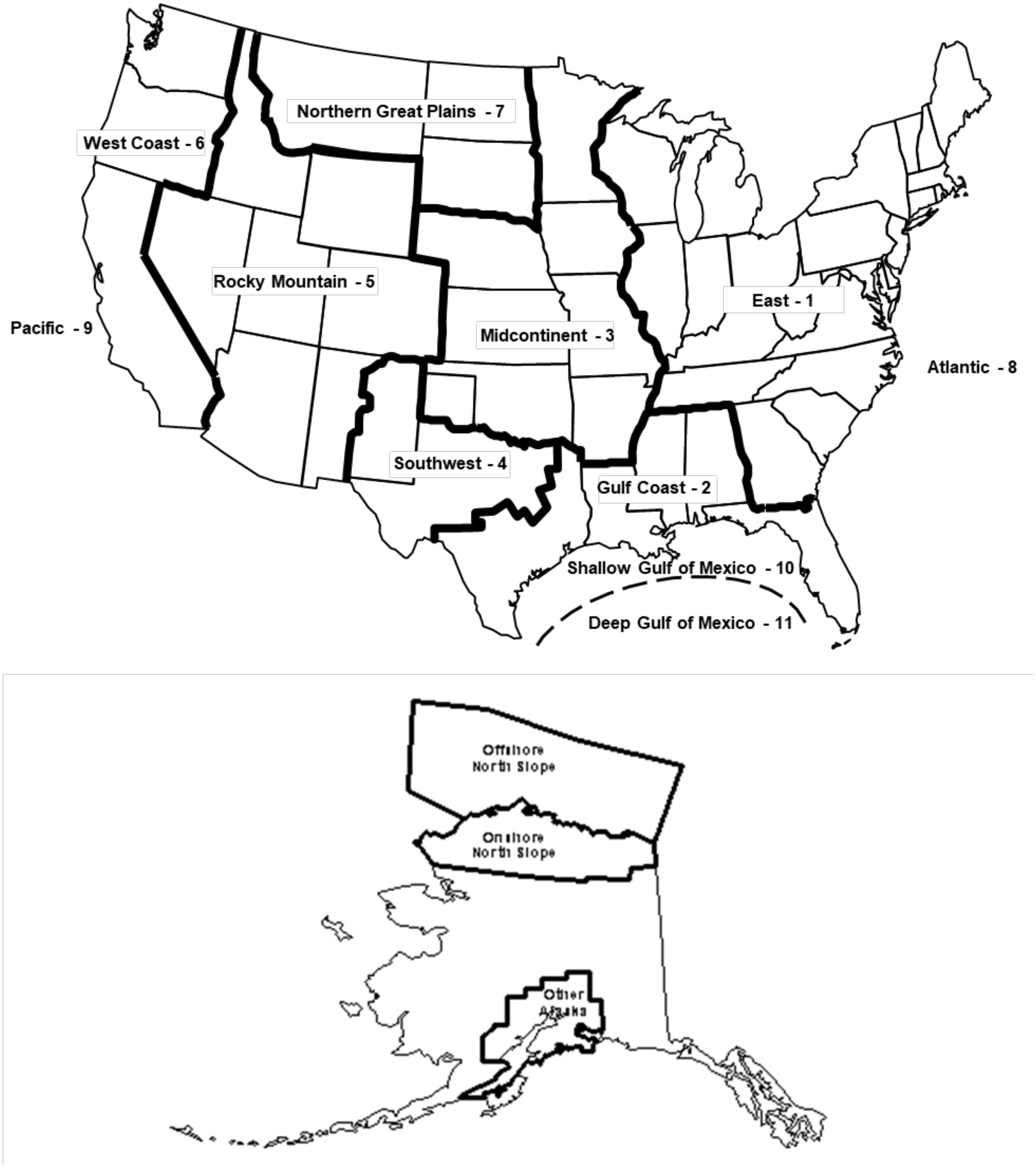
The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable crude oil and natural gas resources[2] for each of the sources of domestic production (in other words, geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

- The uncertainty surrounding the technically recoverable crude oil and natural gas resource estimates
- 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)

[1] Nonassociated (NA) natural gas is 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).

[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 and inferred reserves as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

Figure 1-2. Oil and natural gas supply regions

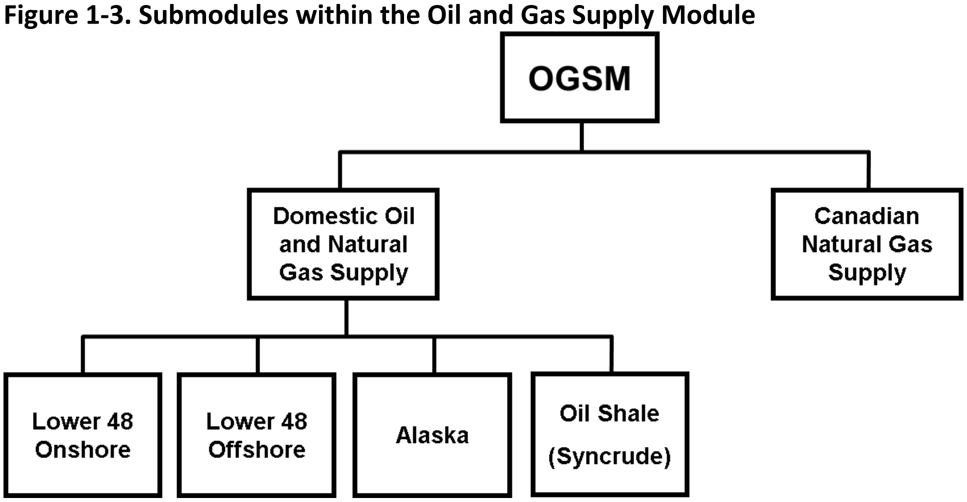


Model structure

The OGSM consists of a set of submodules (Figure 1-3) and is used to perform supply analysis of domestic oil and natural gas as part of NEMS. 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 NEMS. The oil and natural 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 is in the separate methodology documentation reports for the LFMM and the NGMM.

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States. The OGSM encompasses domestic crude oil and natural gas supply and Canada's natural gas supply (excluding production used to support Canada's LNG exports) by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-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. LNG imports and pipeline natural gas import and export trade with Canada and Mexico are determined in the NGMM.

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 natural gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the LFMM and the NGMM 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 natural 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 breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production. The present OGSM 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 states. The Offshore Oil and Gas Supply Submodule (OOGSS) models crude oil and natural gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The Canadian Natural Gas Supply Submodule (CNGSS) models Canada's natural gas production (excluding natural gas production needed to support Canada's LNG exports). The distinctions of each submodule are explained in individual chapters covering methodology. Following the methodology chapters, four appendixes are included:

- Appendix A provides a description of the discounted cash flow (DCF) calculation.

Appendix B is the bibliography.
Appendix C contains a model abstract.
Appendix D is an inventory of key output variables.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

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

The OLOGSS uses both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data include technical production for each project considered, cost and development constraint data, tax information, and project development data. The NGMM provides regional projections of natural gas wellhead prices and production. The LFMM provides projections of crude oil wellhead prices at the OGSM regional level.

Model purpose

OLOGSS analyzes crude oil and natural gas supply potential and related economic issues. Primarily, it projects production of crude oil and natural gas from the onshore Lower 48 states in response to price data received from the LFMM and the NGMM. The OLOGSS does not project prices.

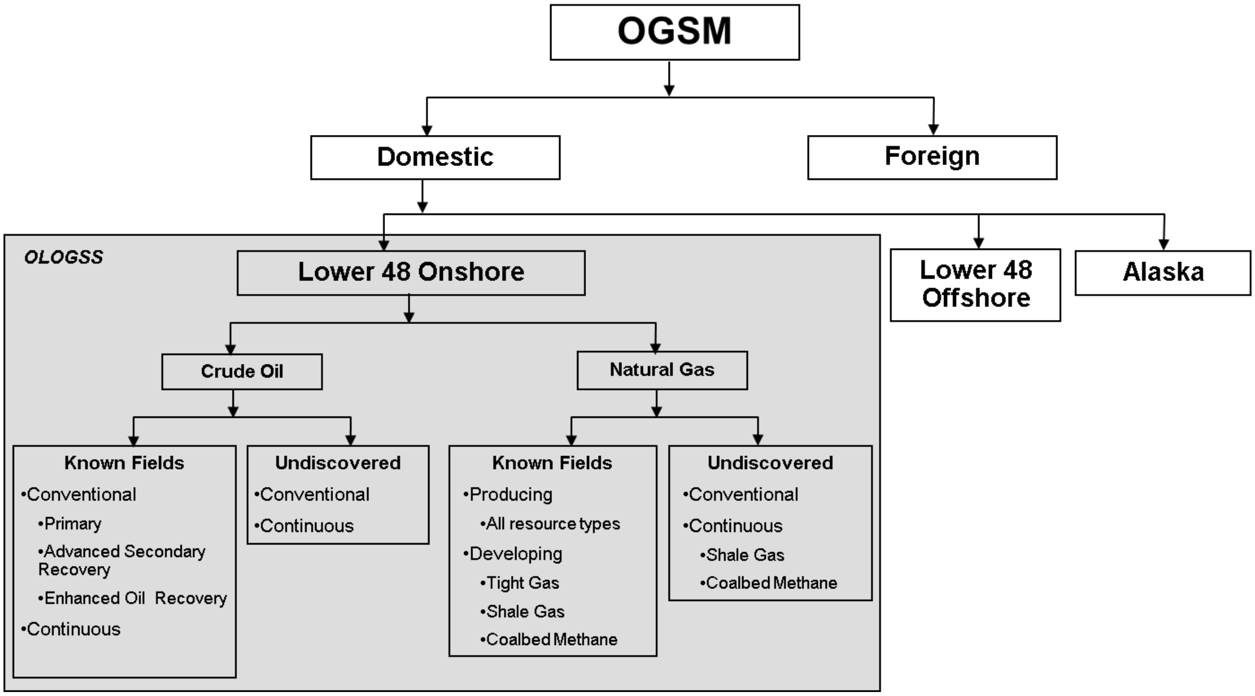
The basic interaction between OLOGSS and the OGSM is illustrated in Figure 2-1. OLOGSS models the entirety of the domestic crude oil and natural gas production within the onshore Lower 48 states.

Resources modeled

Crude oil resources

Crude oil resources are divided into known fields and undiscovered fields (Figure 2-1). 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, including waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing 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, characterized in a method similar to that used for discovered resources, are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on the U.S. Geological Survey (USGS) estimates and is distinguished as either conventional or 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 close 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 are divided into known producing fields, developing natural gas plays, and undiscovered fields (Figure 2-1). Exogenous production-type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based on USGS resource estimates. 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 Onshore Lower 48 Oil and Gas Supply Submodule

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 that projects the crude oil and natural gas supply from the onshore Lower 48 states. 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. Technological 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 and various economic parameters. 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 provides a variety of levers that allows the user to model developments affecting the profitability of development:

- Federal and state tax provisions
- Weighted average cost of capital (discount rate)
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

In addition, OLOGSS can quantify the effects of hypothetical developments that affect the resource base. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (in other words, geographic region/fuel type combinations).

OLOGSS can be used to analyze access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible as a result of development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

Model structure

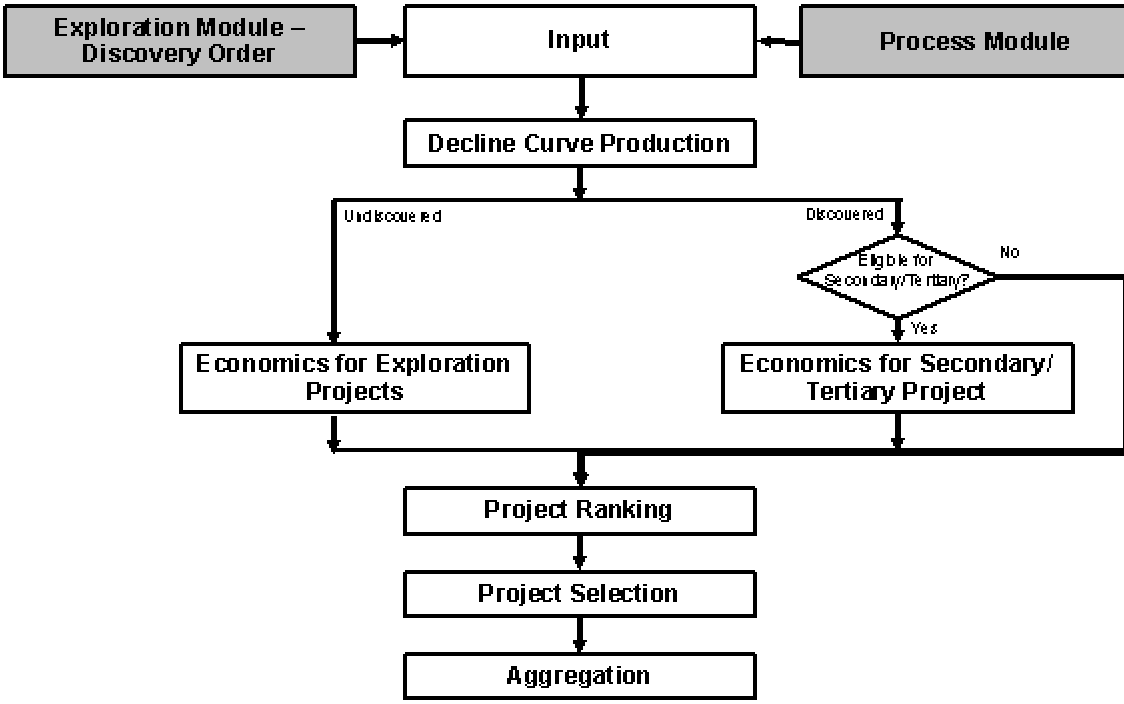
The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development to mimic the way decisions are made by the oil and natural 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 2-2 provides the overall system logic for the OLOGSS timing and economic module and illustrates two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects that may be discovered in the next 30 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. The first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis (Figure 2-2). 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 that determines their economic viability and profitability.

Figure 2-2. OLOGSS timing module overall system logic



For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based on 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. Eligible projects are subject to the same type of economic analysis applied to existing and exploration projects 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 sufficient development resources are 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 natural gas industries. If sufficient resources are not available for an economic project, it 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 and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document provides 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 estimated. A detailed economic analysis is conducted to calculate the economically viable production and the expected life of each project. The project life is used to determine when a project becomes eligible for EOR and ASR processes.

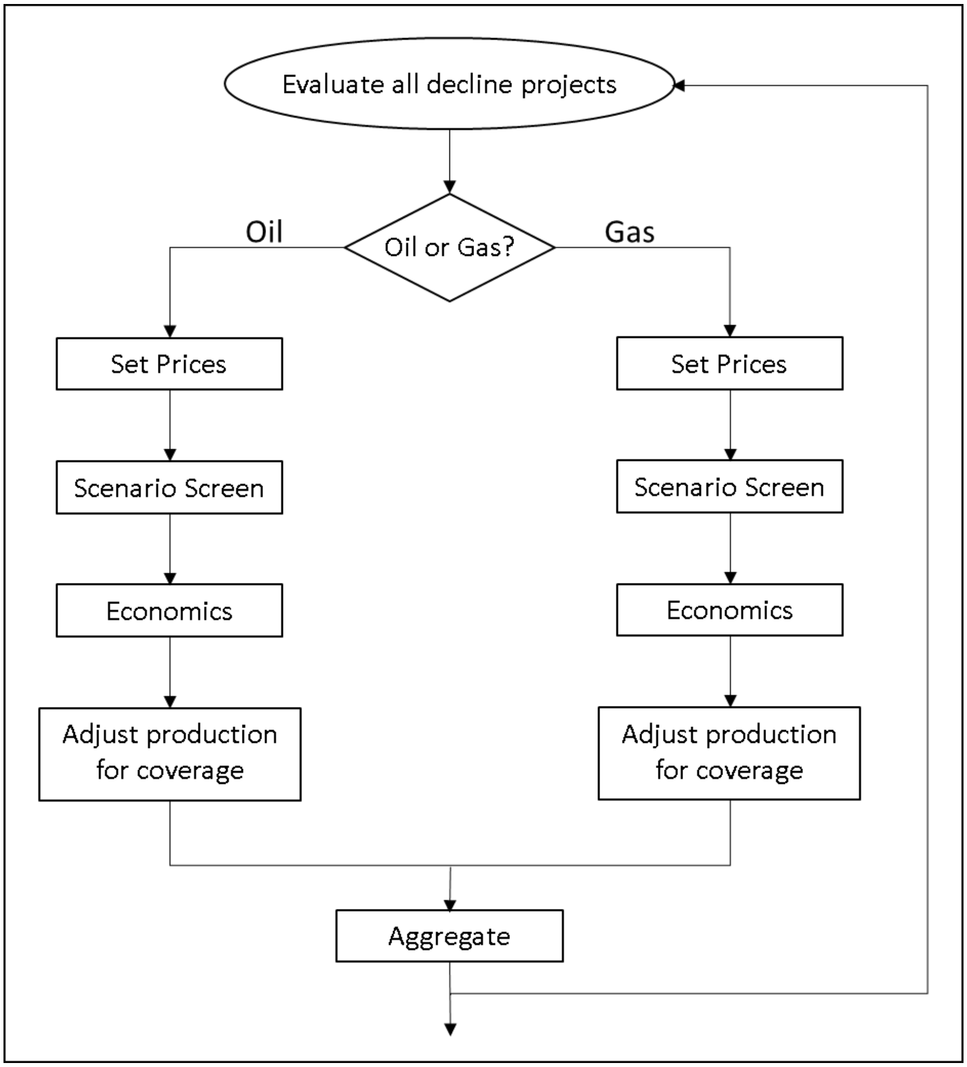
Figure 2-3 outlines the logic for this process. For each crude oil project, regional prices are set, and the project is screened to determine whether the user has specified any technology or economic levers. The screening considers factors including region, process, depth, and several other petro-physical 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 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 what we report. These factors are calculated at the regional level and applied to production data for the following resources:

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

Figure 2-3. Decline process flowchart



Economics

Project costs

OLOGSS conducts the economic analysis of each 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, and the advanced case includes technology or cost improvements associated with applied model levers.

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 cash flow 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 (Figure 2-4).

The details of the calculations used in conducting the economic analysis of a project are:

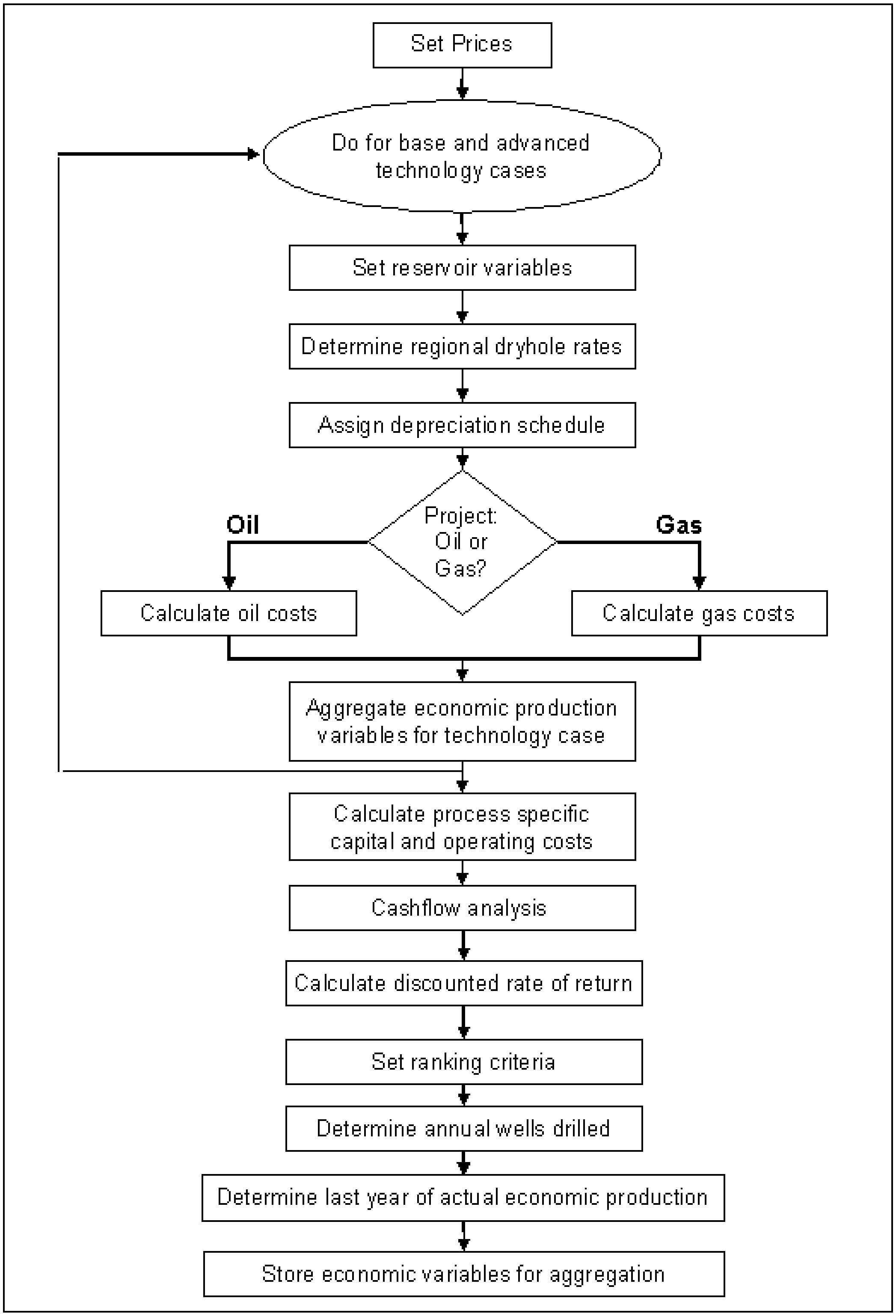
Determine the project shift: The first step is to determine the number of years the project development is shifted, in other words, the number of years between the discovery of a project and the start of its development. This number will be used to determine the crude oil and natural gas price shift. The number of years depends on both the development schedule—when the project drilling begins— and on the process.

Determine annual prices: The next step is to determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use the average price for the previous five years.

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

Determine the dryhole rate for the project: We then assign 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 2-4. Economic analysis logic



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

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

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

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

If evaluating horizontal continuity or horizontal profile, then,

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

If evaluating developing natural gas resources, then:

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

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 CO_2 flooding, steam flooding, or waterflooding 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: This step calculates the geological and geophysical (G&G) factor for each technology case. This factor is added to the first-year cost.

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

where

GG_{itech}	=	G&G 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.

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

Calculate the discounted rate of return: Determines the projected rate of return for all investments and production. The cumulative investments and discounted after-tax cash flow 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. The model tracks five drilling categories:

1. New production wells drilled
2. New injection wells drilled
3. Active production wells
4. Active injection wells
5. Shut-in wells

The calculation of the annual well count depends on the number of existing production and injection wells and on 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 based on the results of the cash flow 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 economical only in the first year, it will be considered uneconomical and unavailable for development at that time. If this situation occurs for an existing crude oil or natural gas project, the model will assume that all of the wells will be shut in.

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 cash flow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion, specified by the user, is the parameter by which the projects will be sorted before development. 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 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 Consumer Price Index (CPI). 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 on 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 (Figure 2-5).

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. The model uses three broad categories of costs: capital costs, operating costs, and other costs (Figure 2-6). Capital costs encompass the costs of drilling and equipment necessary to produce crude oil and natural gas resources. Operating costs are used to calculate the full lifecycle 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 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. These costs fall into two categories: costs that are applied to all processes (resource-independent costs [Table 2-2]) and costs that are applied to specific processes (resource-dependent costs [Table 2-3]). Resource-dependent costs 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 resource-independent costs, and then the resource-dependent costs. Table 2-2 outlines the resource-independent costs, and Table 2-3 outlines the and resource-dependent costs.

Figure 2-5. Project cost calculation procedure

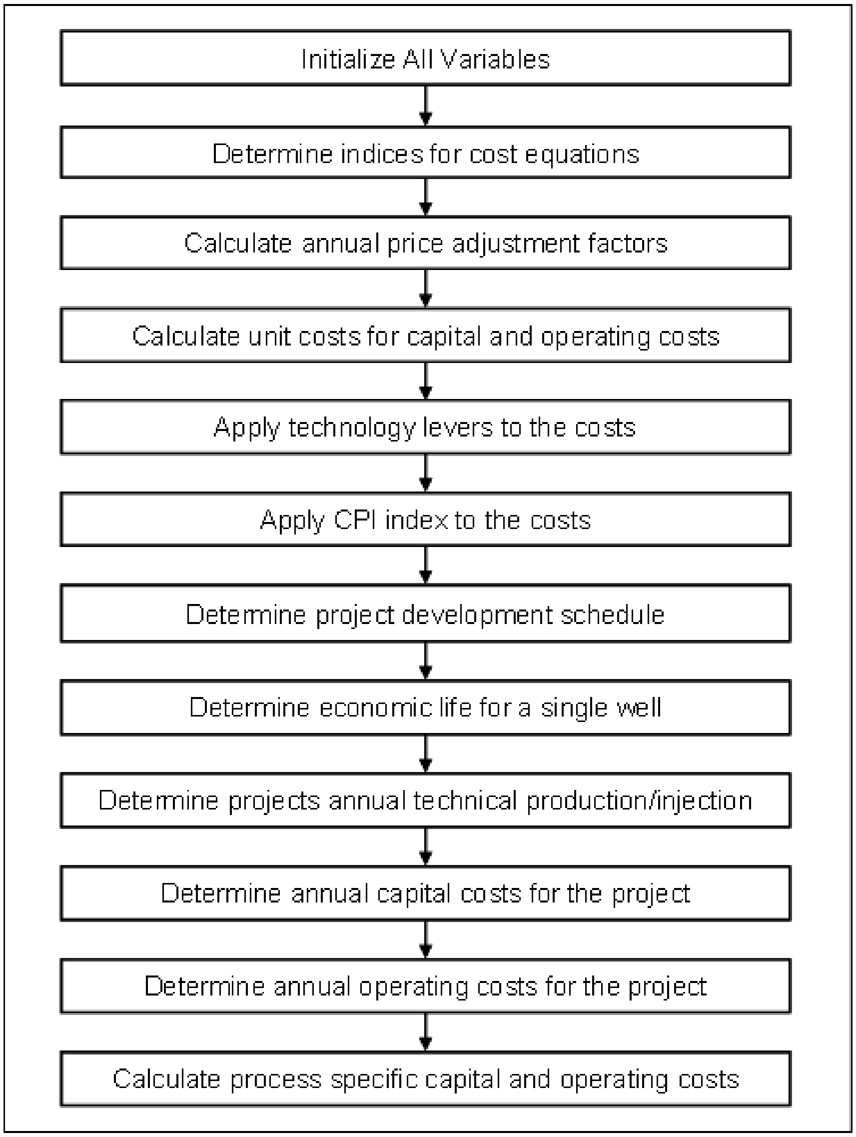


Figure 2-6. Cost data types and requirements

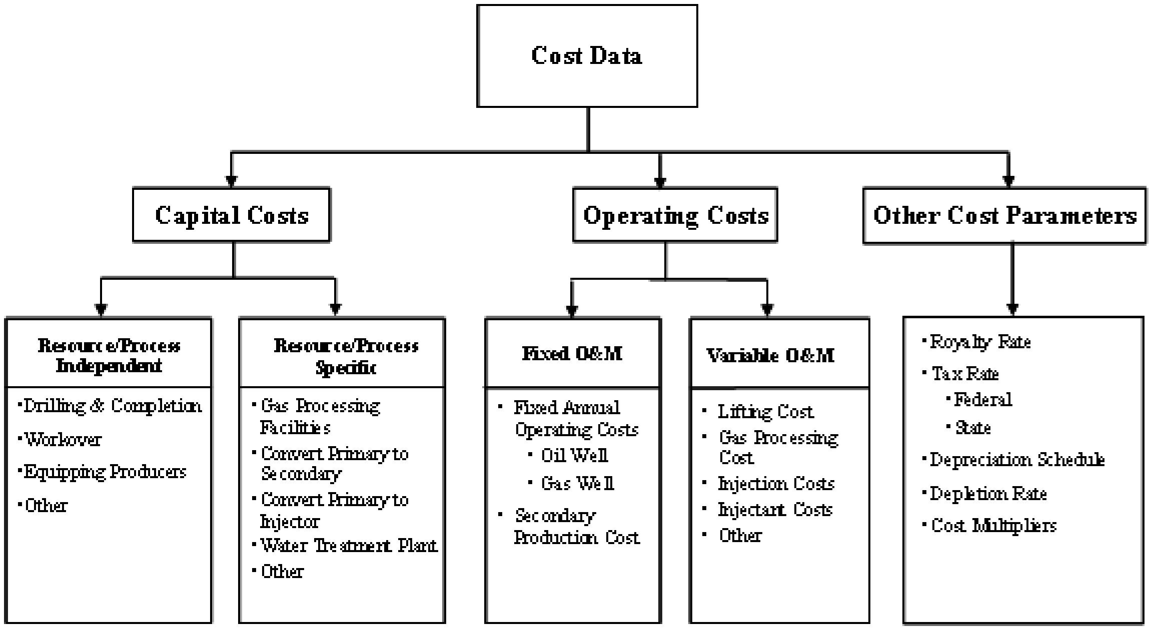


Table 2-2. Costs applied to crude oil processes

Resource-Independent	Vertical drilling cost	√	√	√	√	√	√	√	√
	Horizontal drilling cost								
	Drilling cost for dryhole	√	√	√	√	√	√	√	√
	Cost to equip a primary producer		√	√	√	√	√	√	√
	Workover cost		√	√	√	√	√	√	√
	Facilities upgrade cost		√	√	√	√	√	√	
	Fixed annual cost for oil wells	√	√	√	√	√	√	√	√
	Fixed annual cost for secondary production		√	√	√	√	√	√	√
	Lifting cost		√	√	√	√	√	√	√
	O&M cost for active patterns		√			√		√	
	Variable O&M costs	√	√	√	√	√	√	√	√
	Secondary workover cost		√	√	√	√	√	√	√
	Cost of water handling plant		√			√		√	
Resource-Dependent	Cost of chemical plant					√			
	CO_2 recycle plant			√					
	Cost of injectant					√			
	Cost to convert a primary to secondary well		√	√	√	√	√	√	√
	Cost to convert a producer to an injector		√	√	√	√	√	√	√
	Fixed O&M cost for secondary operations		√	√	√	√	√	√	√
	Cost of a water injection plant		√						
	O&M Cost for active patterns per year		√			√		√	
	Cost to inject CO_2			√					
	King factor				√				
	Steam manifolds cost				√				
	Steam generators cost				√				
	Cost to inject polymer					√		√	

Table 2-3. Costs applied to natural gas processes

Resource-Independent	Vertical drilling cost	√	√	√	√	√
	Horizontal drilling cost	√	√	√	√	√
	Drilling cost for dryhole	√	√	√	√	√
	Natural gas facilities cost	√	√	√	√	√
	Fixed annual cost for natural gas wells	√	√	√	√	√
	Natural gas stimulation costs	√	√	√	√	√
	Overhead costs	√	√	√	√	√
	Variable O&M cost	√	√	√	√	√
Resource-Dependent	Natural gas processing and treatment facilities	√	√	√	√	√

The following section details the formulas 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's (NETL) 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 injectants are applied while calculating project costs. The investment multipliers are applied during the cash flow 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 each year falls lower than a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price:

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

$$\mathrm{INTANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_INT} * \mathrm{TERM}_{iyr}) \tag{2-8}$$

$$\mathrm{TANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_TANG} * \mathrm{TERM}_{iyr}) \tag{2-9}$$

$$OAM\_M_{iyr} = 1.0 + (OMULT\_OAM * TERM_{iyr}) \quad (2\text{-}10)$$

where

iyr	=	Year
TERM	=	Fractional change in crude oil prices (from base price)
OILPRICE	=	Crude oil price
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 operations and maintenance (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

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

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

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

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

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:

$$FPLY = 1.0 + (0.3913 * TERM_{iyr}) \tag{2-15}$$

$$FCO2 = \frac{0.5 + 0.013 * BASEOIL * (1.0 + TERM_{iyr})}{0.5 + 0.013 * BASEOIL} \tag{2-16}$$

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 as follows: 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, excluding the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled.

Drilling and completion costs

$$DWC\_W_r = DNCC\_COEF_{1,1,r} * \exp(-DNCC\_COEF_{1,2,r} * DEPTH)$$
$$+ DNCC\_COEF_{1,3,r} * (DEPTH + NLAT*LATLEN) + DNCC\_COEF_{1,4,r} * (DEPTH + NLAT*LATLEN)^2$$
$$+ DNCC\_COEF_{1,5,r} * \exp(DNCC\_COEF_{1,6,r} * DEPTH) \qquad (2\text{-}17)$$

where

DWC_W	=	Cost to drill and complete a crude oil well (thousand $/well)
r	=	Region number
DNCC_COEF	=	Coefficients for drilling cost equation
DEPTH	=	Well depth (feet)
NLAT	=	Number of laterals
LATLEN	=	Length of lateral (feet)

Drilling costs for a dry well

$$DRY\_W_r = DNCC\_COEF_{3,1,r} * \exp(-DNCC\_COEF_{3,2,r} * DEPTH)$$
$$+ DNCC\_COEF_{3,3,r} * (DEPTH + NLAT*LATLEN) + DNCC\_COEF_{3,4,r} * (DEPTH + NLAT*LATLEN)^2$$
$$+ DNCC\_COEF_{3,5,r} * \exp(DNCC\_COEF_{3,6,r} * DEPTH) \qquad (2\text{-}18)$$

where

DRY_W	=	Cost to drill a dry well (thousand $/well)
r	=	Region number
DNCC_COEF	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral (feet)

Cost to equip a new producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W_{r,d} = NPRK_{r,d} + (NPRA_{r,d} * DEPTH) + (NPRB_{r,d} * DEPTH^2)$$
$$+ (NPRC_{r,d} * DEPTH^3) \qquad (2\text{-}19)$$

where

NPR_W = Cost to equip a new producer (thousand $/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 two to three years to increase the productivity of a producing well. In some cases, workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W_{r,d} = WRKK_{r,d} + (WRKA_{r,d} * DEPTH) + (WRKB_{r,d} * DEPTH^2) + (WRKC_{r,d} * DEPTH^3) \quad (2\text{-}20)$$

where

WRK_W = Cost for a well workover (thousand $/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 incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W_{r,d} = FACUPK_{r,d} + (FACUPA_{r,d} * DEPTH) + (FACUPB_{r,d} * DEPTH^2) + (FACUPC_{r,d} * DEPTH^3) \quad (2\text{-}21)$$

where

FAC_W = Well facilities upgrade cost (thousand $/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, excluding the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Drilling and completion costs:

$$DWC\_W_r = DNCC\_COEF_{2,1,r} * \exp(-DNCC\_COEF_{2,2,r} * DEPTH)$$
$$+ DNCC\_COEF_{2,3,r} * (DEPTH + NLAT*LATLEN) + DNCC\_COEF_{2,4,r} * (DEPTH + NLAT*LATLEN)^2$$
$$+ DNCC\_COEF_{2,5,r} * \exp(DNCC\_COEF_{2,6,r} * DEPTH) \quad (2\text{-}22)$$

where

DWC_W = Cost to drill and complete a natural gas well (thousand $/well)

r = Region number

DNCC_COEF = Coefficients for drilling cost equation

DEPTH = Well depth

NLAT = Number of laterals

LATLEN = Length of lateral

Drilling costs for a dry well

$$DRY\_W_r = DNCC\_COEF_{3,1,r} * \exp(-DNCC\_COEF_{3,2,r} * DEPTH)$$
$$+ DNCC\_COEF_{3,3,r} * (DEPTH + NLAT*LATLEN) + DNCC\_COEF_{3,4,r} * (DEPTH + NLAT*LATLEN)^2$$
$$+ DNCC\_COEF_{3,5,r} * \exp(DNCC\_COEF_{3,6,r} * DEPTH) \quad (2\text{-}23)$$

where

DRY_W = Cost to drill a dry well (thousand $/well)

r = Region number

DNCC_COEF = 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 are incurred 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.

$$FWC\_W_{r,d} = FACGK_{r,d} + (FACGA_{r,d} * DEPTH) + (FACGB_{r,d} * PEAKDAILY\_RATE) + (FACGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}24)$$

where

FWC_W = Facilities cost for a natural gas well (thousand $/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 are applied to natural gas projects in decline curve analysis.

$$FOAMG\_W_{r,d} = OMGK_{r,d} + (OMGA_{r,d} * DEPTH) + (OMGB_{r,d} * PEAKDAILY\_RATE) + (OMGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}25)$$

where

FOAMG_W = Fixed annual operating costs for natural gas (thousand $/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 are applied to crude oil projects in decline curve analysis.

$$OMO\_W_{r,d} = OMOK_{r,d} + (OMOA_{r,d} * DEPTH) + (OMOB_{r,d} * DEPTH^2) + (OMOC_{r,d} * DEPTH^3) \quad (2\text{-}26)$$

where

OMO_W	=	Fixed annual operating costs for crude oil wells (thousand $/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.

$$OPSEC\_W_{r,d} = OPSECK_{r,d} + (OPSECA_{r,d} * DEPTH) + (OPSECB_{r,d} * DEPTH^2) + (OPSECC_{r,d} * DEPTH^3) \quad (2\text{-}27)$$

where

OPSEC_W	=	Fixed annual operating cost for secondary oil operations (thousand $/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.

$$OML\_W_{r,d} = OMLK_{r,d} + (OMLA_{r,d} * DEPTH) + (OMLB_{r,d} * DEPTH^2) + (OMLC_{r,d} * DEPTH^3) \quad (2\text{-}28)$$

where

OML_W	=	Variable annual operating cost for lifting (thousand $/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 two to three 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.

$$SWK\_W_{r,d} = OMSWRK_{r,d} + (OMSWR\,A_{r,d} * DEPTH) + (OMSWR\,B_{r,d} * DEPTH^2) + (OMSWR\,C_{r,d} * DEPTH^3) \quad (2\text{-}29)$$

where

SWK_W	=	Secondary workover costs (thousand $/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 two to three years to increase the productivity of a producing well. In some cases, workover or stimulation of a wellbore is required to maintain production rates.

$$STIM\_W = \left(\frac{STIM\_A + STIM\_B * DEPTH}{1000}\right) \quad (2\text{-}30)$$

where

STIM_W	=	Oil stimulation costs (thousand $/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.

$$PSW\_W_{r,d} = PSWK_{r,d} + (PSWA_{r,d} * DEPTH) + (PSWB_{r,d} * DEPTH^2) + (PSWC_{r,d} * DEPTH^3) \quad (2\text{-}31)$$

where

PSW_W	=	Cost to convert a primary well into a secondary well (thousand $/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 2⅞-inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$PSI\_W_{r,d} = PSIK_{r,d} + (PSIA_{r,d} * DEPTH) + (PSIB_{r,d} * DEPTH^2) + (PSIC_{r,d} * DEPTH^3) \quad (2\text{-}32)$$

where

PSI_W	=	Cost to convert a producing well into an injecting well (thousand $/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 (thousand barrels) throughout the life of the project.

$$\text{PWP\_F} = \text{PWHP} * \left(\frac{\text{RMAXW}}{365}\right) \tag{2-33}$$

where

PWP_F	=	Cost of the produced water handling plant (thousand $/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.

$$\text{CHM\_F} = \text{CHMK} * \text{CHMA} * \left(\frac{\text{RMAXP}}{365}\right)^{\text{CHMB}} \tag{2-34}$$

where

CHM_F	=	Cost of chemical handling plant (thousand $/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.

$$\text{PLY\_F} = \text{PLYPK} * \text{PLYPA} * \left(\frac{\text{RMAXP}}{365}\right)^{0.6} \tag{2-35}$$

where

PLY_F	=	Cost of polymer handling plant (thousand $/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 (thousand cubic feet [Mcf]) throughout the project life. If the maximum CO_2 rate equals or exceeds 60,000 barrels (b) per day, then the costs are divided into two separate plant costs.

$$CO2\_F = CO2RK * \left(\frac{0.75 * RMAXP}{365}\right)^{CO2RB} \tag{2-36}$$

where,

CO2_F = Cost of CO2 recycling plant (thousand $/well)

CO2RK, CO2RB = Coefficients for CO2 recycling plant cost equation

RMAXP = Maximum pattern level annual CO2 injection rate

Cost of steam manifolds and pipelines: The cost to install and maintain steam manifolds and pipelines are added for steam flood EOR project.

$$STMM\_F = TOTPAT * PATSZE * STMMA \tag{2-37}$$

where

STMM_F = Cost for steam manifolds and generation (thousand $)

TOTPAT = Total number of patterns in the project

PATSZE = Pattern size (acres)

STMMA = Steam manifold and pipeline cost (per acre)

Resource-dependent annual operating costs for crude oil

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

$$OPINJ\_W_{r,d} = OPINJK_{r,d} + (OPINJA_{r,d} * DEPTH) + (OPINJ\,B_{r,d} * DEPTH^2) + (OPINJ\,C_{r,d} * DEPTH^3) \tag{2-38}$$

where

OPINJ_W = Variable annual operating cost for injection (thousand $/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 for 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 (2-39)

where

POLYCOST = Cost of polymer (dollars per pound)

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))) * CO2PR(IST) (2-40)

where

CO2COST = Cost of natural CO2 (dollars per thousand cubic feet [$/Mcf])

IST = State identifier

CO2K, CO2B = Coefficients for natural CO2 cost equation

OILPRICEO(1) = Crude oil price for first year of project analysis

CO2PR = State CO2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO2 cost: Cost to capture and transport CO2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site by pipeline.

Industrial CO_2 sources include:

- Hydrogen plants

- Ammonia plants
- Ethanol plants
- Cement plants
- Hydrogen refineries
- Power plants
- Natural gas processing plants
- Coal-to-liquids plants

The regional costs, which are specific to the industrial source of CO_2, are exogenously determined and provided in the input file, except for power plants and coal-to-liquids 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:

$$NPR\_W = (UNPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \quad (2\text{-}41)$$

where

NPR_W	=	Cost to equip a new oil producer (thousand $/well)
UNPR_W	=	Cost to equip a new oil producer before technology adjustments (thousand $/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)

The costs for CO_2 from power plants and coal-to-liquids plants are determined in the Capture, Transport, Utilization, and Storage (CTUS) Submodule and passed to OGSM (Appendix 2.D).

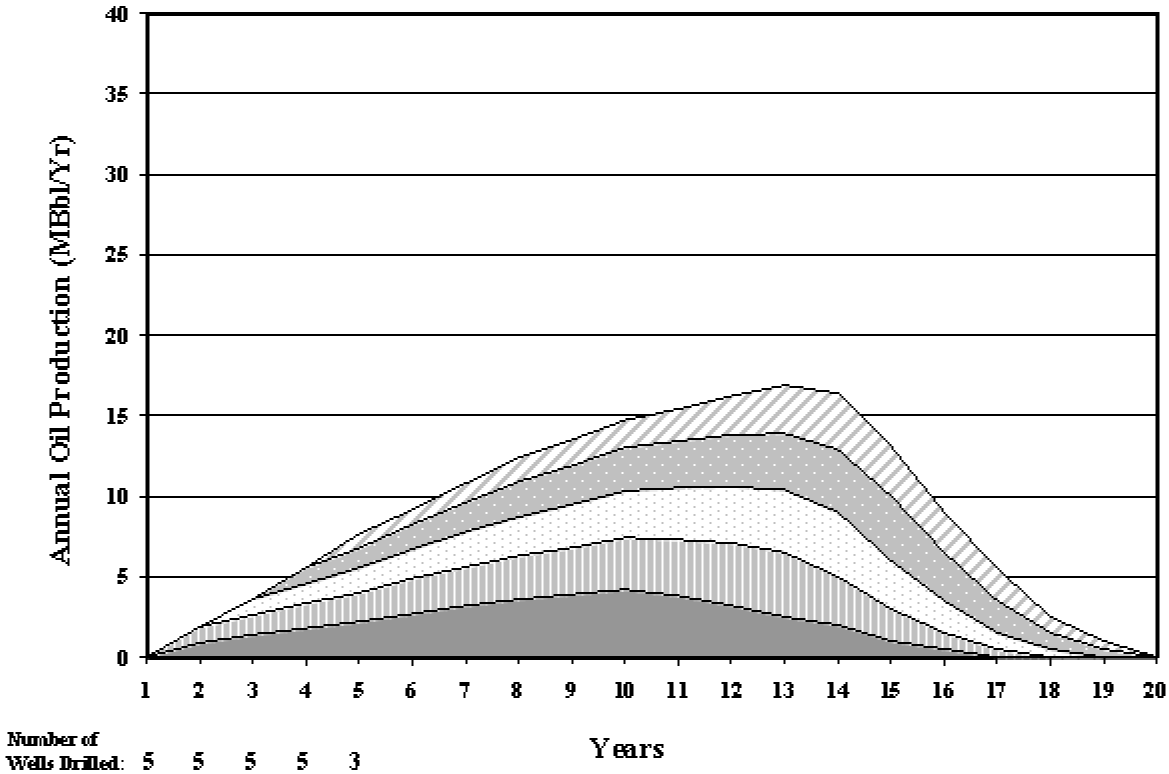
Determining technical production

The development schedule algorithms determine how the project's development over time will be modeled. They calculate the number of wells 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 well life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-7 shows the crude oil production for one hypothetical project over the course of its life. In this scenario, new wells are drilled over the course of five years. Each shaded area is the annual technical production associated with the active wells by vintage year.

Figure 2-7. Calculating project-level technical production



The first step in modeling the technical production is to calculate the number of wells 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 wells developed each year is reduced if the resource is subject to cumulative surface use limitations
The total number of wells needed to develop the project
The crude oil and natural gas prices
Expected production rate in first year to allow highgrading—for example, drilling is reduced more in low productivity areas than in high productivity areas when prices decrease
The user-specified maximum and minimum number of wells developed each year
The user-specified percentage of the project to be developed each year
The percentage of the project that is using base or advanced technology

After calculating the number of wells drilled each year, the model calculates the number of wells that are active (producing) for each year of the project's life.

Crude Oil and Natural Gas 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—the sum of the well-level production for each profile gives the estimated ultimate recovery per well (EUR). For infill projects, the production is doubled because the model assumes that there are two producers in each pattern. These profiles change during the projection period depending on the assumed impact of technological progress (increases the expected per well production rate, see technology section on page 63) and diminishing returns as horizontal tight and shale wells are drilled closer together (the productivity of each new well eventually is reduced as they start to interfere with each other). The impact of diminishing returns is realized when the spacing of wells drops to less than 100 acres and is represented by:

$$\text{adjusted\_prod\_profile}_t = \text{orig\_prod\_profile}_t * \left(1.0 - \frac{1.0}{1.0 + \exp\left(-\left[\frac{INT\left\lfloor latlen * \frac{870}{43{,}560}\right\rfloor}{wlspc_{year}} - 2.0\right]\right)}\right) \tag{2-42}$$

where

adjusted_prod_profile	=	Revised production profile for tight/shale oil and natural gas wells that are drilled in areas with less than 100-acre well spacing
orig_prod_profile	=	Original production profile for tight/shale oil and natural gas wells
latlen	=	Lateral length (feet)
wlspc	=	Well spacing (acres)
t	=	Normalized year of production (first year (1)–last year (30))
year	=	Projection year (2016–2050)

Crude Type: Production from each play/sub-play has an assumed average API gravity (degrees) and sulfur content (percentage). Crude oil production (including lease condensates) is grouped into the following crude type categories:

- Light sweet: 35 ≤ API < 40, sulfur < 0.5
- Light sour: API≥ 35, sulfur ≥ 0.5
- Medium medium sour: 27 ≤ API <35, sulfur < 1.1
- Medium sour: 27 ≤ API <35, sulfur ≥ 1.1
- Heavy sweet: API < 27, sulfur < 1.1
- Heavy sour: API < 27, sulfur ≥ 1.1

- California: all API and sulfur
- Syncrude: not produced in U.S.
- DilBit/SynBit: not produced in U.S.
- Ultra light sweet: 40 ≤ API < 50, sulfur < 0.5
- 50+ sweet: API≥ 50, sulfur < 0.5

Natural gas plant liquids production: The revenue generated from the production of natural gas plant liquids (NGPLs) is included in the economic evaluation of the project. NGPLs are determined by applying a play-level factor (in barrels per million cubic feet) to the well-level natural gas production profile. The price applied to the NGPL volumes is the industrial LPG feedstock price determined in the LFMM. The composition of NGPL production is determined using assumed shares of ethane, propane, butane, isobutene, and pentanes plus.

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 wells in each category depends on 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 using one of four approaches, depending on the resource and recovery process. These approaches apply to the following resources:

- 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 assumption is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = (DWC\_W * PATN_{iyr} + DRY\_W * REGDRYUE_R + DRY\_W * REGDRYUD_R * (PATN_{iyr} - 1)) * XPP1 \quad (2\text{-}43)$$

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

$$DRL\_CST2_{iyr} = (DWC\_W + DRY\_W * REGDRYKD_R) * (PATDEV_{ires,iyr,itech} * XPP1) \quad (2\text{-}44)$$

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

$$DRL\_CST2_{iyr} = (DWC\_W + DRY\_W * REGDRYKD_r) * (PATN_{iyr} * XPP1) \quad (2\text{-}45)$$

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

$$DRL\_CST2_{iyr} = (DWC\_W + DRY\_W * REGDRYUD_r) * (PATN_{iyr} * XPP1) \quad (2\text{-}46)$$

where

ires	=	Project index number
iyr	=	Year
R	=	Region
PATDEV	=	Number of wells drilled each year for base and advanced technology cases
PATN	=	Annual number of wells drilled
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 depend on 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:

$$FACCOST_{iyr} = (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}47)$$

For existing natural gas fields:

$$FACCOST_{iyr} = (FWC\_W * (PATDEV_{ires,iyr,itech}) * XPP1) \quad (2\text{-}48)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}49)$$

For existing crude oil fields:

$$FACCOST_{iyr} = (PSW\_W * (PATDEV_{ires,iyr,\ itech}) * XPP4) \quad (2\text{-}50)$$

$$+ (PSI\_W * PATDEV_{ires,iyr,\ itech} * XPP3)$$

$$+ (FAC\_W * PATDEV_{ires,iyr,\ itech} * (XPP1 + XPP2))$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$FACCOST_{iyr} = (PSW\_W * PATN_{iyr} * XPP4) \quad (2\text{-}51)$$

$$+ (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2))$$

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 added to the operating and maintenance costs.

$$INJ_{iyr} = INJ\_OAM1 * WATINJ_{iyr} \quad (2\text{-}52)$$

where

iyr = Year

INJ = Annual injection cost

INJ_OAM1 = Process-specific cost of injection (dollars per barrel [$/b])

WATINJ = Annual project level water injection

For infill drilling: Injectant costs are zero.

Fixed annual operating costs for crude oil:

For CO2 EOR:

$$AOAM_{iyr} = OPSEC\_W * SUMP_{iyr} \quad (2\text{-}53)$$

For undiscovered conventional crude oil:

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

For all crude oil processes except CO2 EOR:

$$AOAM_{iyr} = (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \quad (2\text{-}54)$$

Fixed annual operating costs for natural gas:

For existing natural gas fields:

$$AOAM_{iyr} = (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \quad (2\text{-}55)$$

For undiscovered and developing natural gas resources:

$$AOAM_{iyr} = (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \quad (2\text{-}56)$$

where

AOAM = Annual fixed operating and 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:

$$OAM_{iyr} = (OILPROD_{iyr} * OIL\_OAM1 + GASPROD_{iyr} * GAS\_OAM1 + WATPROD_{iyr} * WAT\_OAM1) * OAM\_M_{iyr} + INJ_{iyr}$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \quad (2\text{-}57)$$

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 ($/b)

GAS_OAM1 = Process-specific cost of natural gas production ($/Mcf)

WAT_OAM1 = Process-specific cost of water production ($/b)

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:

$$COMP_{iyr} = COMP_{iyr} + (COMP\_W * PATN_{iyr} * XPP1) \tag{2-58}$$

O&M cost for compression:

$$OAM\_COMP_{iyr} = OAM\_COMP_{IYR} + (GASPROD_{iyr} * COMP\_OAM * OAM\_M_{iyr}) \tag{2-59}$$

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 O&M 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 is added to the first-year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \tag{2-60}$$

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 is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \quad (2\text{-}61)$$

where

FACCOST$_1$ = First year of project facilities costs

PWP_F = Produced water handling plant cost

Advanced CO2: Other costs added to the facilities costs include the facilities cost for a CO2 handling plant and a recycling plant, the O&M (fixed and variable) cost for a CO2 handling plant and recycling plant, and injectant cost. 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.

$$FACCOST_1 = FACCOST_1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365} \right)^{CO2RB} \right) * 1{,}000 \quad (2\text{-}62)$$

$$FACCOST_6 = FACCOST_6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365} \right)^{CO2RB} \right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \quad (2\text{-}63)$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \quad (2\text{-}64)$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \quad (2\text{-}65)$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \quad (2\text{-}66)$$

where

iyr = Year

RMAX = Maximum annual volume of recycled CO2

CO2OAM = O&M cost for CO2 handling plant

CO2OAM2 = The O&M cost for the project’s CO2 injection plant

CO2RK, CO2RB = CO2 recycling plant cost coefficients

PSW_W = Cost to convert a primary well to a secondary well

INJ = Cost of purchased CO2

TOTINJ = Annual project-level volume of injected CO2

TORECY = Annual project-level CO2 recycled volume

CO2COST = Cost of CO2 ($/Mcf)

OAM = Annual variable O&M costs

OAM_M = Energy elasticity factor for O&M costs

FOAM = Fixed annual operating and maintenance costs

FCO2 = Energy elasticity factor for CO2

FACCOST = Annual project facilities costs

TORECY_CST = The annual cost of operating the CO2 recycling plant

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

Recalculate the facilities costs: Facilities costs include the capital cost for injection plants, which is based upon the original oil in place (OOIP) of the project, the steam recycling plant, and the steam generators required for the project.

$$FACCOST_1 = FACCOST_1 + \left(\frac{OOIP * 0.1 * 2.0 * APAT}{TOTPAT}\right) + (RECY\_WAT * RMAXWAT$$

$$+ RECY\_OIL * RMAXOIL) + (STMMA * TOTPAT * PATSIZE)$$

$$+ (IGEN_{iyr} - IG) * STMGA \qquad (2\text{-}67)$$

$$OAM_{iyr} = OAM_{iyr} + (WAT\_OAM1 * WATPROD_{iyr} * OAM\_M_{iyr}) + (OIL\_OAM1$$

$$* OILPROD_{iyr} * OAM\_M_{iyr}) + (INJ\_OAM1 * WATINJ_{iyr} * OAM\_M_{iyr}) \qquad (2\text{-}68)$$

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 (million barrels [MMb])

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 ($/b)

OIL_OAM1 = Process-specific cost of crude oil production ($/b)

INJ_OAM1 = Process-specific cost of water injection ($/b)

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.

$$INJ_{iyr} = INJ_{iyr} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \quad (2\text{-}69)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}70)$$

where

iyr	=	Year
INJ	=	Annual injection cost
OAM_M	=	Energy elasticity factor for operating and maintenance 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

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

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1{,}000} \quad (2\text{-}71)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}72)$$

where

IYR	=	Year
INJ	=	Annual injection cost
TOTINJ	=	Annual project-level injectant volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable O&M cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Waterflood: Add the O&M cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}73)$$

where

iyr	=	Year
OAM	=	Annual variable O&M cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

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

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

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5} \right) \quad (2\text{-}75)$$

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 ($/b)
GAS_OAM1	=	Process-specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process-specific cost of water production ($/b)
OAM_M	=	Energy elasticity factor for O&M costs
OPSEC_W	=	Fixed annual operating cost for secondary well operations
SUMP	=	Cumulative patterns developed
AOAM	=	Fixed annual O&M costs
OAM	=	Variable annual O&M 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:

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}76)$$

$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}77)$$

where

itech	=	Technology case (base or 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. Eligible projects are subject to an economic analysis and are passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects, while the second applies to EOR/ASR and developing natural gas projects.

Figure 2-8 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 so not considered.

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

- No leasing because of statutory or executive order
- Leasing available but cumulative timing limitations between three and nine 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. Timing logic applied to the EOR/ASR projects as well as the developing natural gas projects (Figure 2-9).

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 condition does not apply to the developing natural gas projects.

If the project meets all of these conditions, then it is considered eligible for economic analysis. For an EOR/ASR project to be considered for timing, it must be within a process-specific EOR/ASR development window (Table 2-4).

Table 2-4. EOR/ASR eligibility ranges

Process	Before economic limit	After economic limit
CO2 flooding	After 2009	10 Years
Steam flooding	5 Years	10 Years
Polymer flooding	5 Years	10 Years
Infilll 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 evaluated. A different analytical approach is applied to CO2 EOR and all other projects. For non-CO2 EOR projects, the project is screened for applicable technology levers, and the economic analysis is conducted. CO2 EOR projects are treated differently because of the different CO2 costs associated with the different sources of industrial and natural CO2.

For each available source, the economic variables are calculated and stored. These variables include the source of CO_2 and the project's 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. Before evaluation, the constraints, resource access, and technology and economic levers are checked, and the technology case is set.

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. Resources or processes are considered in this step:

EOR processes:

- CO_2 flooding
- Steam flooding
- Polymer flooding
- Profile modification

ASR processes:

- Waterflooding
- 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 (Table 2-4).

Project ranking: Sorts exploration and EOR/ASR projects that are economical and so eligible for timing. The subroutine matches the discovery order for undiscovered projects and sorts the others by ranking criterion. The criteria include:

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

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

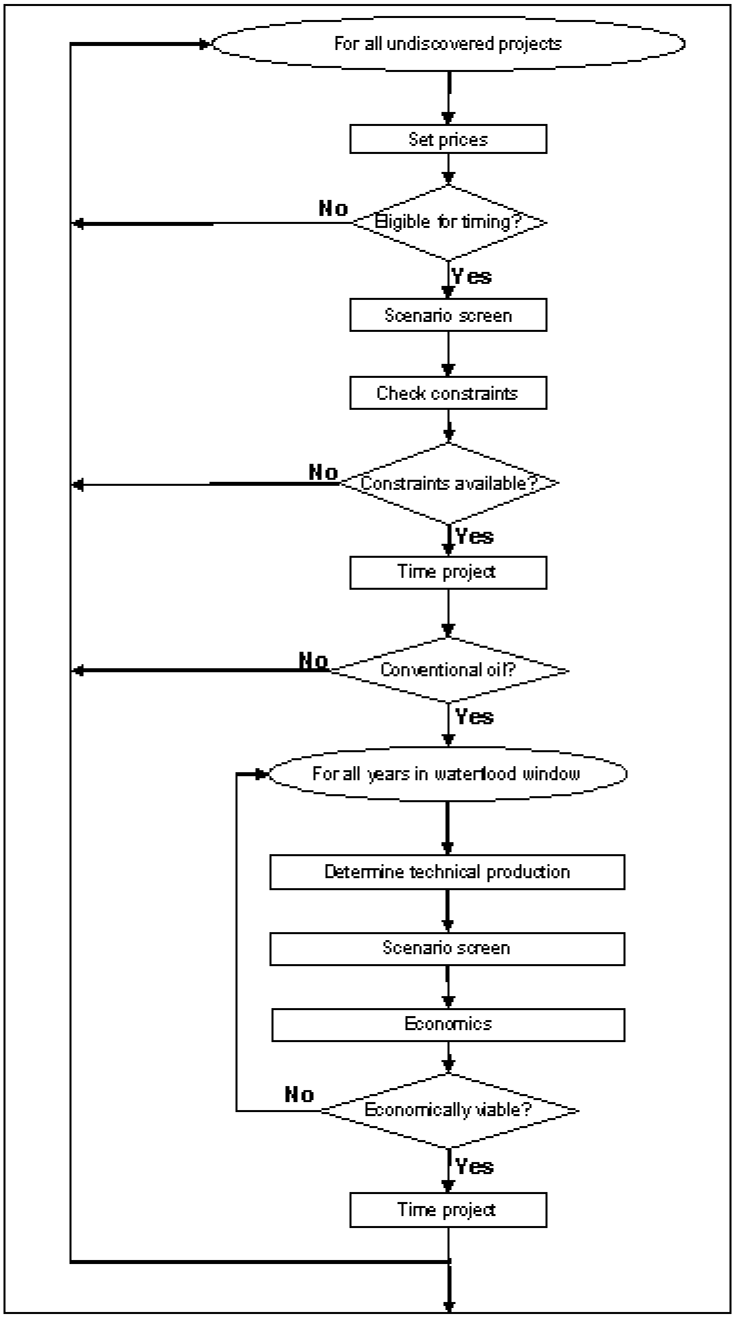
Project selection

The project selection subroutine determines which exploration, EOR/ASR, and developing natural gas projects will be modeled as developed in each year analyzed. In addition, this subroutine determines if waterflooding is performed on conventional undiscovered crude oil projects.

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 2-8.

Figure 2-8. Selecting undiscovered projects



The prices are set for the project before its eligibility is checked (Figure 2-8). Eligibility requirements are:

- The project is economically viable.
- The project is not previously timed and developed.

Eligible projects are screened for applicable technologies that affect the drilling success rates. The development constraints required for the project are checked against those that 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 that are eligible, economically viable, and undeveloped because of a lack of development resources are considered again for future projection 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 on 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 economical, it is timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine applies to EOR/ASR projects as well as the developing natural gas projects (Figure 2-9).

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 the candidate project for both economic viability and eligibility for timing. Afterwards, the project is screened for any applicable technology and economic levers.

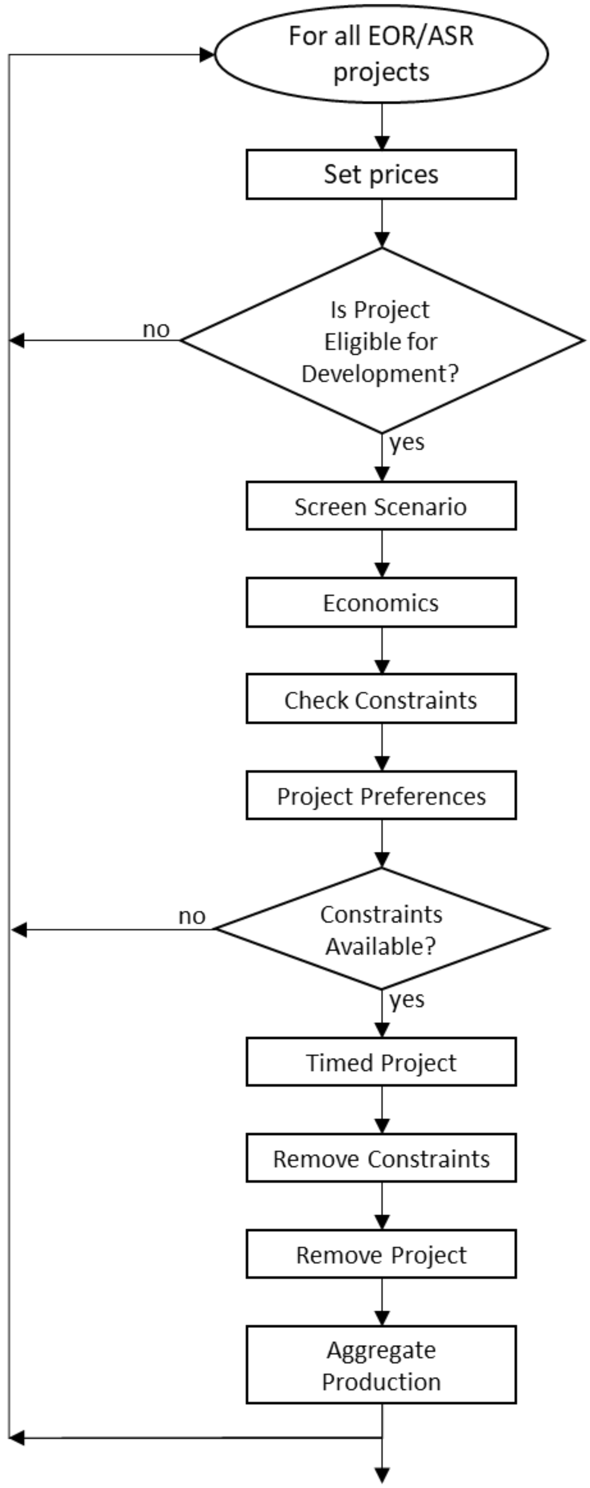
If the project is eligible for CO_2 EOR, the economics are run for each specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules that govern the competition between projects and selection of projects:

- CO_2 EOR and infill drilling are available after 2010.
- Profile modification becomes available after 2011.
- 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.

Figure 2-9. Selecting EOR/ASR projects



If the project is timed, the constraints are then 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 with two 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.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If a project is economical and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. The model assumes that the 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 if it is both eligible for implementation and economically viable.

EOR/ASR projects

When considering whether a project is eligible for EOR/ASR processing, the model first checks for the availability of sufficient development resources.

Constraints

Resource development constraints are used during the selection of projects for development to mimic the infrastructure limitations of the oil and natural gas industry. The model assumes that only the projects that do not exceed the constraints available will be developed.

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 each 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.

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:

$$TOT\_GROWTH_{iyr} = \left(1.0 + \frac{DRILL\_OVER}{100}\right) \tag{2-78}$$

For the remaining years:

$$TOT\_GROWTH_{iyr} = TOT\_GROWTH_{iyr\text{-}1} * \left(1.0 + \frac{RGR}{100}\right) * \left(1 - \frac{RRR}{100}\right) * \left(1.0 + \frac{DRILL\_OVER}{100}\right) \tag{2-79}$$

where

iyr	=	Year evaluated
TOT_GROWTH	=	Annual growth change for drilling at the national level (fraction)
DRILL_OVER	=	Percentage of drilling constraint available for footage overrun
RGR	=	Annual rig development rate (percentage)
RRR	=	Annual rig retirement rate (percentage)

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

$$NAT\_OIL_{iyr} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH_{iyr} * OIL\_ADJ_{iyr} \tag{2-80}$$

$$NAT\_GAS_{iyr} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH_{iyr} * GAS\_ADJ_{iyr} \tag{2-81}$$

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, OILA1, GASA0, GASA1 = 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 footage for drilling is calculated at the national level, regional allocations are used to we allocate the drilling to each of the OLOGSS regions. The drilling that is not allocated, as a result of the *drill trans* factor, is available in any region and represents the drilling that can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$\text{REG\_OIL}_{\text{j,iyr}} = \text{NAT\_OIL}_{\text{iyr}} * \left(\frac{\text{PRO\_REGOIL}_{\text{j}}}{100}\right) * \left(1.0 - \frac{\text{DRILL\_TRANS}}{100}\right) \tag{2-82}$$

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 is transferrable among regions.

PRO_REGOIL = Regional development oil footage allocation (percentage)

DRILL_TRANS = Percentage of footage that is transferable among regions

Footage constraints: The model determines whether sufficient footage is 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:

$$\text{FOOTREQ}_{\text{ii}} = (\text{DEPTH}_{\text{itech}} * (1.0 + \text{SUC\_RATEKD}_{\text{itech}})) * \text{PATDEV}_{\text{irs,ii-itimeyr+1,itech}} \tag{2-83}$$

$* (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech}$

$* PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech}$

For exploration projects:

For the first year of the project: (2-84)

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

For all other project years:

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech}) \quad (2\text{-}85)$$

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.

$$FOOTREQii = FOOTREQii + (ALATNUM_{irs,itech} * ALATLEN_{irs,itech} * (1.0 + SUC\_RATEKD_{itech}) * PATDEV_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}86)$$

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 available for the project. The available footage is specific to the resource, the process, and the constraint options that 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: Nine rig-depth rating categories are used to determine whether a rig is available that can drill to the depth required by the project (Table 2-5).

Table 2-5. Rig depth categories

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

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

$$RDR\_FOOTAGE_{j,\,iyr} = (NAT\_TOT_{iyr} + NAT\_EXP_{iyr} + NAT\_EXPG_{iyr}) * \frac{RDR_j}{100} \quad (2\text{-}87)$$

where

j = Rig-depth rating category

iyr = Year

RDR_FOOTAGE = Footage available in this interval (thousand feet)

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_j = Percentage of rigs that can drill to depth category *j*

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based on their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on investments the oil and natural gas industry can make in a 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 NGMM 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, natural gas processing plants, and coal-to-liquids plants.

For CO_2 sources other than power plants and coal-to-liquids plants, the maximum volume of CO_2 available for EOR is determined exogenously and provided in the input file. Technology and market constraints prevent the total volumes of CO_2 produced from becoming immediately available. The development of the CO_2 market is divided into three periods:

- Technology R&D
- Infrastructure construction
- Market acceptance

The capture technology is under development during the R&D phase, and no CO_2 produced by the technology is assumed available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is assumed available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 are assumed to become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry that will adopt the technology has adopted it, providing an upper limit on the volume of CO_2 that will be available. Figure 2-10 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.

The volume of CO_2 captured from power plants is determined in the Electricity Market Module and coal-to-liquids plants is determined in the Liquid Fuels Market Module.

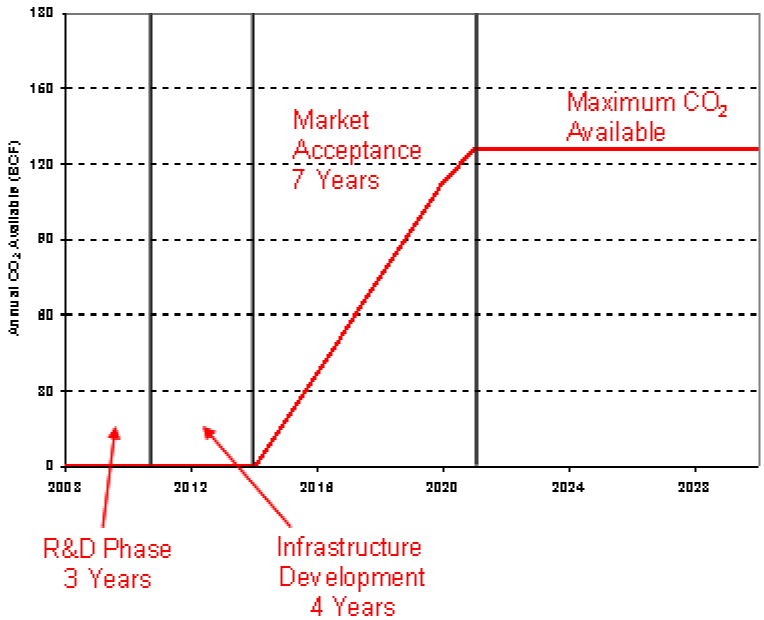
CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: Restrictions on access to federal lands constrain the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing because of statutory or executive order
- Leasing available but cumulative timing limitations between three and nine months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was estimated using data from the U.S. Department of Interior’s inventory of onshore Federal oil and natural gas resources.

Figure 2-10. CO_2 market acceptance curve



Technology

The OLOGSS uses a simplified approach to modeling the impact of technology advancement on U.S. crude oil and natural gas costs and productivity to better capture a continually changing technological landscape. This approach incorporates assumptions regarding ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources plus cumulative production from 1990 between AEO2000 and AEO2015.

Areas in tight oil, tight gas, and shale gas plays are divided into two productivity tiers with different assumed rates of technology change. The first tier (Tier 1) encompasses actively developing areas, and the second tier (Tier 2) encompasses areas not yet under development. Once development begins in a Tier 2 area, the rate of technological improvement doubles for wells drilling in the early development phase as producers determine how to efficiently extract the hydrocarbons and where the sweet spots are (learning by doing). This area is then converted to Tier 1, so technological improvement for continued drilling will reflect the rates assumed for Tier 1 areas. This conversion captures the effects of diminishing returns on a per-well basis from decreasing well spacing as development progresses, from the rapid market penetration of technologies, and from the ready application of industry practices and technologies at the time of development. The specific assumptions for the annual average rate of technological improvement are shown in Table 2.6.

Table 2-6. Onshore Lower 48 technology assumptions

Tight gas	-1.00%	-0.50%	1.00%	3.00%	6.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%	6.00%
All other	-0.25%	-0.25%	0.25%	0.25%	0.25%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

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	
ABOI	Input	Initial formation volume factor	
ABTU	Variable	Btu content	Btu/cf
ACER	Input	ACE rate	Percentage
ACHGASPROD	Input	Cumulative historical natural gas production	Million cubic feet (MMcf)
ACHOILPROD	Input	Cumulative historical crude oil production	Mb
ACO2CONT	Input	CO2 impurity content	Percent
ACRDTYPE	Variable	Crude type category	
ADEPTH	Input	Depth	Feet (ft)
ADGGLA	Variable	Depletable items in the year (G&G and lease acquisition cost)	thousand $
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	thousand $
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/b
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	Natural gas/oil ratio	Mcf/b
AH2SCONT	Input	Hydrogen sulfide (H2S) impurity content	percentage
AHCPV	Variable	Hydro Carbon Pore Volume	1.0 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/cf
AINJINJ	Input	Annual injectant injected	Mb, Mcf, thousand pounds (Mlbs)
AINJRECY	Variable	Annual injectant recycled	Mb, Mcf
ALATLEN	Input	Lateral length	ft
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf
ALYROIL	Input	Last year of historical crude oil production	Mb
AMINT	Variable	Alternative minimum income tax	thousand $
AMOR	Variable	Intangible investment depreciation amount	thousand $
AMOR_BASE	Variable	Amortization base	thousand $
AMORSCHL	Input	Annual fraction amortized	Fraction

Variable Name	Variable Type	Description	Unit
AMT	Input	Alternative minimum tax	thousand $
AMTRATE	Input	Alternative minimum tax rate	thousand $
AN2CONT	Input	Dinitrogen (N2) impurity content	Percent
ANGL	Input	Natural gas plant liquids factor	b/MMcf
ANGPLBU	Input	Butane share of NGPL composition	Fraction
ANGPLET	Input	Ethane share of NGPL composition	Fraction
ANGPLIS	Input	Isobutane share of NGPL composition	Fraction
ANGPLPP	Input	Pentane plus share of NGPL composition	Fraction
ANGPLPR	Input	Propane share of NGPL composition	Fraction
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	thousand $
AOGIP	Variable	Original natural gas in place	Bcf
AOILVIS	Input	Crude oil viscosity	Centipoise (CP)
AOOIP	Variable	Original oil in place (OOIP)	Mb
AORGOOIP	Input	Original OOIP	Mb
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	ft
APD	Variable	Annual percent depletion	thousand $
APERM	Input	Permeability	Millidarcy (MD)
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	Pounds per square inch absolute (PSIA)
APRODCO2	Input	Annual CO2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual natural gas liquids (NGL) production	Mb
APRODOIL	Input	Annual crude oil production	Mb
APRODWAT	Input	Annual water production	Mb
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir size class	
ASGI	Variable	Natural gas saturation	Percent
ASOC	Input	Current oil saturation	Percent

Variable Name	Variable Type	Description	Unit
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	Percent
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cash flow	thousand $
ATEMP	Variable	Reservoir temperature	Degrees Fahrenheit
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	Mb
AWOR	Input	Water/oil ratio	b/b
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	thousand $
BSE_AVAILCO2	Variable	Base annual volume of CO2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	thousand $
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cash flow	thousand $
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 CO2 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

Variable Name	Variable Type	Description	Unit
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	thousand $
CHG_OINJ_FAC	Input	Change in injection O&M cost	thousand $
CHG_OOIL_FAC	Input	Change in oil O&M cost	thousand $
CHG_OWAT_FAC	Input	Change in water O&M cost	thousand $
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	thousand $
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	thousand $
CO2_F	Variable	Cost for a CO2 recycling/injection plant	thousand $
CO2_RAT_ FAC	Input	CO2 injection factor	
CO2AVAIL	Variable	Total CO2 available in a region across all sources	Bcf/y
CO2BASE	Input	Total volume of CO2 available	Bcf/y
CO2COST	Variable	Final cost for CO2	$/Mcf
CO2B	Input	Constant and coefficient for natural CO2 cost equation	
CO2K	Input	Constant and coefficient for natural CO2 cost equation	
CO2MUL	Input	CO2 availability constraint multiplier	
CO2OAM	Variable	CO2 variable O&M cost	thousand $
CO2OM_20	Input	The O&M cost for CO2 injection < 20 MMcf	thousand $
CO2OM20	Input	The O&M cost for CO2 injection > 20 MMcf	thousand $
CO2PR	Input	State/regional multipliers for natural CO2 cost	
CO2PRICE	Input	CO2 price	$/Mcf
CO2RK, CO2RB	Input	CO2 recycling plant cost	thousand $
CO2ST	Input	State code for natural CO2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	thousand $
COMP_OAM	Variable	Compressor O&M cost	thousand $

Variable Name	Variable Type	Description	Unit
COMP_VC	Input	Compressor O&M costs	thousand $
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	thousand $
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	$/Boiler Horsepower (Bhp)
COTYPE	Variable	CO2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
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 CO2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well-level cost to apply secondary producer technology	thousand $
CST_ANNSEC_CSTP	Variable	Project-level cost to apply secondary producer technology	thousand $
CST_CMP_CSTP	Variable	Project-level cost to apply compression technology	thousand $
CST_CMP_FAC	Input	Well-level cost to apply compression technology	thousand $
CST_COMP_ FAC	Input	Well-level cost to apply completion technology	thousand $
CST_COMP_CSTP	Variable	Project-level cost to apply completion technology	thousand $
CST_DRL_ FAC	Input	Well-level cost to apply drilling technology	thousand $
CST_DRL_CSTP	Variable	Project-level cost to apply drilling technology	thousand $
CST_FAC_ FAC	Input	Well-level cost to apply facilities technology	thousand $
CST_FAC_CSTP	Variable	Project-level cost to apply facilities technology	thousand $
CST_FACUPG_ FAC	Input	Well-level cost to apply facilities upgrade technology	thousand $
CST_FACUPG_CSTP	Variable	Project-level cost to apply facilities upgrade technology	thousand $
CST_FOAM_ FAC	Input	Well-level cost to apply fixed annual O&M technology	thousand $
CST_FOAM_CSTP	Variable	Project-level cost to apply fixed annual O&M technology	thousand $
CST_GNA_ FAC	Input	Well-level cost to apply G&A technology	thousand $

Variable Name	Variable Type	Description	Unit
CST_GNA_CSTP	Variable	Project-level cost to apply G&A technology	thousand $
CST_INJC_ FAC	Input	Well-level cost to apply injection technology	thousand $
CST_INJC_CSTP	Variable	Project-level cost to apply injection technology	thousand $
CST_INJCONV_ FAC	Input	Well-level cost to apply injector conversion technology	thousand $
CST_INJCONV_CSTP	Variable	Project-level cost to apply injector conversion technology	thousand $
CST_LFT_ FAC	Input	Well-level cost to apply lifting technology	thousand $
CST_LFT_CSTP	Variable	Project-level cost to apply lifting technology	thousand $
CST_SECCONV_ FAC	Input	Well-level cost to apply secondary conversion technology	thousand $
CST_SECCONV_CSTP	Variable	Project-level cost to apply secondary conversion technology	thousand $
CST_SECWRK_ FAC	Input	Well-level cost to apply secondary workover technology	thousand $
CST_SECWRK_CSTP	Variable	Project-level cost to apply secondary workover technology	thousand $
CST_STM_ FAC	Input	Well-level cost to apply stimulation technology	thousand $
CST_STM_CSTP	Variable	Project-level cost to apply stimulation technology	thousand $
CST_VOAM_ FAC	Input	Well-level cost to apply variable annual O&M technology	thousand $
CST_VOAM_CSTP	Variable	Project-level cost to apply variable annual O&M technology	thousand $
CST_WRK_ FAC	Input	Well-level cost to apply workover technology	thousand $
CST_WRK_CSTP	Variable	Project-level cost to apply workover technology	thousand $
CSTP_ANNSEC_ FAC	Input	Project-level cost to apply secondary producer technology	thousand $
CSTP_CMP_ FAC	Input	Project-level cost to apply compression technology	thousand $
CSTP_COMP_ FAC	Input	Project-level cost to apply completion technology	thousand $
CSTP_DRL_ FAC	Input	Project-level cost to apply drilling technology	thousand $
CSTP_FAC_ FAC	Input	Project-level cost to apply facilities technology	thousand $
CSTP_FACUPG_ FAC	Input	Project-level cost to apply facilities upgrade technology	thousand $
CSTP_FOAM_ FAC	Input	Project-level cost to apply fixed annual O&M technology	thousand $
CSTP_GNA_ FAC	Input	Project-level cost to apply G&A technology	thousand $
CSTP_INJC_ FAC	Input	Project-level cost to apply injection technology	thousand $

Variable Name	Variable Type	Description	Unit
CSTP_INJCONV_ FAC	Input	Project-level cost to apply injector conversion technology	thousand $
CSTP_LFT_ FAC	Input	Project-level cost to apply lifting technology	thousand $
CSTP_SECCONV_ FAC	Input	Project-level cost to apply secondary conversion technology	thousand $
CSTP_SECWRK_ FAC	Input	Project-level cost to apply secondary workover technology	thousand $
CSTP_STM_ FAC	Input	Project-level cost to apply stimulation technology	thousand $
CSTP_VOAM_ FAC	Input	Project-level cost to apply variable annual O&M technology	thousand $
CSTP_WRK_ FAC	Input	Project-level cost to apply workover technology	thousand $
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/b
DATCF	Variable	Discounted cash flow after taxes	thousand $
DEP_CRD	Variable	Depletion credit	thousand $
DEPLET	Variable	Depletion allowance	thousand $
DEPR	Variable	Depreciation amount	thousand $
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)	thousand $
DISC_DRL	Variable	Discounted drilling cost	thousand $
DISC_FED	Variable	Discounted federal tax payments	thousand $
DISC_GAS	Variable	Discounted revenue from natural gas sales	thousand $
DISC_INV	Variable	Discounted investment rate	thousand $
DISC_NDRL	Variable	Discounted project facilities costs	thousand $
DISC_OAM	Variable	Discounted O&M cost	thousand $
DISC_OIL	Variable	Discounted revenue from crude oil sales	thousand $
DISC_ROY	Variable	Discounted royalty	thousand $
DISC_ST	Variable	Discounted state tax rate	thousand $
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

Variable Name	Variable Type	Description	Unit
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	Percent
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	Percent
DRILL_TRANS	Input	Drilling constraints transfer between regions	Percent
DRILLCST	Variable	Drill cost by project	thousand $
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	thousand $
DRY_CST	Variable	Dryhole drilling cost	thousand $
DRY_DWCA	Estimated	Dryhole well cost	thousand $
DRY_DWCB	Estimated	Dryhole well cost	thousand $
DRY_DWCC	Estimated	Dryhole well cost	thousand $
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	thousand $
DRYCST	Variable	Dryhole cost by project	thousand $
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	
DWC_W	Variable	Cost to drill and complete a crude oil well	thousand $
EADGGLA	Variable	G&G and lease acquisition cost depletion	thousand $
EADJGROSS	Variable	Adjusted revenue	thousand $
EAMINT	Variable	Alternative minimum tax	thousand $
EAMOR	Variable	Amortization	thousand $
EAOAM	Variable	Fixed annual operating cost	thousand $
EATCF	Variable	After-tax cash flow	thousand $
ECAP_BASE	Variable	Depreciable/capitalized base	thousand $
ECATCF	Variable	Cumulative discounted after-tax cash flow	thousand $
ECO2CODE	Variable	CO2 source code	
ECO2COST	Variable	CO2 cost	thousand $
ECO2INJ	Variable	Economic CO2 injection	Bcf/y
ECO2LIM	Variable	Source-specific project life for CO2 EOR projects	
ECO2POL	Variable	Injected CO2	MMcf
ECO2RANKVAL	Variable	Source-specific ranking value for CO2 EOR projects	

Variable Name	Variable Type	Description	Unit
ECO2RCY	Variable	CO2 recycled	Bcf/y
ECOMP	Variable	Compressor tangible capital	thousand $
EDATCF	Variable	Discounted after tax cash flow	thousand $
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	thousand $
EDEPGGLA	Variable	Depletable G&G/lease cost	thousand $
EDEPLET	Variable	Depletion	thousand $
EDEPR	Variable	Depreciation	thousand $
EDGGLA	Variable	Depletion base	thousand $
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	thousand $
EEGGLA	Variable	Expensed G&G and lease acquisition cost	thousand $
EEORTCA	Variable	Tax credit addback	thousand $
EEXIST_ECAP	Variable	Environmental existing capital	thousand $
EEXIST_EOAM	Variable	Environmental existing O&M costs	thousand $
EFEDCR	Variable	Federal tax credits	thousand $
EFEDROY	Variable	Federal royalty	thousand $
EFEDTAX	Variable	Federal tax	thousand $
EFOAM	Variable	CO2 FOAM cost	thousand $
EGACAP	Variable	G&A capitalized	thousand $
EGAEXP	Variable	G&A expensed	thousand $
EGASPRICE2	Variable	Natural gas price used in the economics	$/Mcf
EGG	Variable	Expensed G&G cost	thousand $
EGGLA	Variable	Expensed G & G and lease acquisition cost	thousand $
EGGLAADD	Variable	G&G/lease addback	thousand $
EGRAVADJ	Variable	Gravity adjustment	thousand $
EGROSSREV	Variable	Gross revenues	thousand $
EIA	Variable	Environmental intangible addback	thousand $
EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EII	Variable	Intangible investment	thousand $
EIIDRL	Variable	Intangible investment drilling	thousand $
EINJCOST	Variable	CO2/polymer cost	thousand $
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	thousand $
EINTCAP	Variable	Tangible investment drilling	thousand $
EINVEFF	Variable	Investment efficiency	
EITC	Input	Environmental intangible tax credit	thousand $

Variable Name	Variable Type	Description	Unit
EITCAB	Input	Environmental intangible tax credit rate addback	Percent
EITCR	Input	Environmental intangible tax credit rate	thousand $
ELA	Variable	Lease and acquisition cost	thousand $
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	Mb
ENETREV	Variable	Net revenues	thousand $
ENEW_ECAP	Variable	Environmental new capital	thousand $
ENEW_EOAM	Variable	Environmental new O&M costs	thousand $
ENIAT	Variable	Net income after taxes	thousand $
ENIBT	Variable	Net income before taxes	thousand $
ENPV	Variable	Net present value	thousand $
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs flag	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	thousand $
EOCA	Variable	Environmental operating cost addback	thousand $
EOCTC	Input	Environmental operating cost tax credit	thousand $
EOCTCAB	Input	Environmental operating cost tax credit rate addback	Percent
EOCTCR	Input	Environmental operating cost tax credit rate	thousand $
EOILPRICE2	Variable	Crude oil price used in the economics	thousand $
EORTC	Input	EOR tax credit	thousand $
EORTCA	Variable	EOR tax credit addback	thousand $
EORTCAB	Input	EOR tax credit rate addback	Percent
EORTCP	Input	EOR tax credit phase out crude oil price	thousand $
EORTCR	Input	EOR tax credit rate	Percent
EORTCRP	Input	EOR tax credit applied by year	Percent
EOTC	Variable	Other tangible capital	thousand $
EPROC_OAM	Variable	Natural gas processing cost	thousand $
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	Mb
EPRODWAT	Variable	Economic water production	Mb
EPRODWELL	Variable	Active producing wells per year	
EROR	Variable	Rate of return	Percent
EROY	Variable	Royalty	thousand $
ESEV	Variable	Severance tax	thousand $
ESHUTIN	Variable	New shut-in wells drilled per year	

Variable Name	Variable Type	Description	Unit
ESTIM	Variable	Stimulation cost	thousand $
ESTTAX	Variable	State tax	thousand $
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ Mb/ Mlbs
ETAXINC	Variable	Net income before taxes	thousand $
ETCADD	Variable	Tax credit addbacks taken from NIAT	thousand $
ETCI	Variable	Federal tax credit	thousand $
ETCIADJ	Variable	Adjustment for federal tax credit	thousand $
ETI	Variable	Tangible investments	thousand $
ETOC	Variable	Total operating cost	thousand $
ETORECY	Variable	CO2/surf/steam recycling volume	Bcf/Mb/y
ETORECY_CST	Variable	CO2/surf/steam recycling cost	Bcf/Mb/y
ETTC	Input	Environmental tangible tax credit	thousand $
ETTCAB	Input	Environmental tangible tax credit rate addback	Percent
ETTCR	Input	Environmental tangible tax credit rate	Percent
EWATINJ	Variable	Economic water injected	Mb
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	thousand $
EXIST_EOAM	Variable	Existing environmental O&M cost	thousand $
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling that is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling that 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	thousand $
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	Percent
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	Percent
EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	thousand $
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	

Variable Name	Variable Type	Description	Unit
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	thousand $
FACCOST	Variable	Facilities cost	thousand $
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 CO2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	thousand $
FEDTAX_CR	Variable	Federal tax credits	thousand $
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	thousand $
FOAM	Variable	CO2 fixed O&M cost	thousand $
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	thousand $
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	thousand $
FOAMG_W	Variable	Fixed operating cost for natural gas wells	thousand $
FGASPRICE	Input	Fixed natural gas price	$/Mcf
FOILPRICE	Input	Fixed crude oil price	$/b

Variable Name	Variable Type	Description	Unit
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 CO2	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	thousand $
GA_CAP	Variable	G&A on capital	thousand $
GA_EXP	Variable	G&A on expenses	thousand $
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	thousand $
GASPRICEC	Variable	Annual natural gas prices used by cash flow	thousand $

Variable Name	Variable Type	Description	Unit
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	thousand $
GASPRICEO	Variable	Annual natural gas prices used by the model	thousand $
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G&G cost	thousand $
GG_FAC	Input	G&G factor	
GGCTC	Input	G&G tangible depleted tax credit	thousand $
GGCTCAB	Input	G&G tangible tax credit rate addback	Percent
GGCTCR	Input	G&G tangible depleted tax credit rate	thousand $
GGETC	Input	G&G intangible depleted tax credit	thousand $
GGETCAB	Input	G&G intangible tax credit rate addback	Percent
GGETCR	Input	G&G intangible depleted tax credit rate	thousand $
GGLA	Variable	G&G and lease acquisition addback	thousand $
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	thousand $
GMULT_OAM	Input	Natural gas price adjustment factor, O&M	thousand $
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	thousand $
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	thousand $
GROSS_REV	Variable	Gross revenue	thousand $
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	Percent
H_SUCCESS	Input	Horizontal development well success rate by region	Percent
H2SPRICE	Input	H2S 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	thousand $
ICST	Variable	Intangible cost	thousand $
IDCA	Variable	Intangible drilling capital addback	thousand $
IDCTC	Input	Intangible drilling cost tax credit	thousand $
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	Percent

Variable Name	Variable Type	Description	Unit
IDCTCR	Input	Intangible drilling cost tax credit rate	thousand $
IDEPRYR	Input	Number of years in default depreciation schedule	
II_DRL	Variable	Intangible drilling cost	thousand $
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 CO2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on water in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N2 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 CO2?	
INDUSTRIAL	Variable	Natural or industrial CO2 source	
INFLFAC	Input	Annual inflation factor	
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMb, Bcf
INJ	Variable	Injectant cost	thousand $
INJ_OAM	Input	Process-specific operating cost for injection	$/b
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	thousand $
INTANG_M	Variable	Intangible cost multiplier	
INTCAP	Variable	Intangible to be capitalized	thousand $
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternative minimum tax reduction for independents	thousand $
IUNDARES	Variable	Initial undiscovered resource	MMb/trillion cubic feet (Tcf)
IUNDRES	Variable	Initial undiscovered resource	MMb/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	thousand $
LACTC	Input	Lease acquisition tangible depleted tax credit	thousand $
LACTCAB	Input	Lease acquisition tangible credit rate addback	Percent

Variable Name	Variable Type	Description	Unit
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	thousand $
LAETC	Input	Lease acquisition intangible expensed tax credit	thousand $
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	Percent
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	thousand $
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	thousand $
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	Degrees API
MAX_DEPTH_CASE	Input	Maximum depth	ft
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	Degrees API
MIN_DEPTH_CASE	Input	Minimum depth	ft
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	N2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/y
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/y

Variable Name	Variable Type	Description	Unit
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	Mb/y
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/y
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/y
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	Mb/y
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/y
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/y
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/y
NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	Mb
NAT_HOR	Variable	Horizontal drilling constraint	Mb/y
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	Mb/y
NAT_OIL	Variable	National crude oil drilling constraint	Mb/y
NAT_SRCCO2	Input	Use natural source of CO2?	
NAT_TOT	Variable	Total national footage	ft
NET_REV	Variable	Net revenue	thousand $
NEW_ECAP	Variable	New environmental capital cost	thousand $
NEW_EOAM	Variable	New environmental O&M cost	thousand $
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/gal
NGPLPRD	Variable	Annual natural gas plant liquids production	Mb
NGPLPRDBU	Variable	Annual butane production	Mb
NGPLPRDET	Variable	Annual ethane production	Mb
NGPLPRDIS	Variable	Annual isobutane production	Mb
NGPLPRDPP	Variable	Annual pentanes plus production	Mb
NGPLPRDPR	Variable	Annual propane production	Mb
NIAT	Variable	Net income after taxes	thousand $

Variable Name	Variable Type	Description	Unit
NIBT	Variable	Net income before taxes	thousand $
NIBTA	Variable	Net operating income after adjustments before addback	thousand $
NIL	Input	Net income limitations	thousand $
NILB	Variable	Net income depletable base	thousand $
NILL	Input	Net income limitation limit	thousand $
NOI	Variable	Net operating income	thousand $
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	thousand $
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
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	thousand $
OAM_COMP	Variable	Compression O&M	thousand $
OAM_M	Variable	O&M cost multiplier	
OIA	Variable	Other intangible capital addback	thousand $
OIL_ADJ	Input	Fraction of annual crude oil drilling that 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	

Variable Name	Variable Type	Description	Unit
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	$/b
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 CO2 projects	thousand $
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cash flow	thousand $
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	thousand $
OILPRICEO	Variable	Annual crude oil prices used by the model	thousand $
OILPROD	Variable	Annual crude oil production	Mb
OINJ	Variable	Well-level injection	MMcf
OITC	Input	Other intangible tax credit	thousand $
OITCAB	Input	Other intangible tax credit rate addback	Percent
OITCR	Input	Other intangible tax credit rate	thousand $
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	thousand $
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	

Variable Name	Variable Type	Description	Unit
OMLM	Input	Minimum depth range for annual operating cost for crude oil	ft
OMO_W	Variable	Fixed annual operating cost for crude oil	thousand $
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	thousand $
OPERL48	Variable	Operating Costs	1987$/well
OPINJ_W	Variable	Variable annual operating cost for injection	thousand $
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	Mb
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	thousand $

Variable Name	Variable Type	Description	Unit
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	Mb
OTC	Variable	Other tangible costs	thousand $
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	thousand $
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	Percent
PGGC	Input	Percent of G&G depleted	Percent
PIIC	Input	Intangible investment to capitalize	Percent
PLAC	Input	Percentage of lease acquisition cost capitalized	Percent
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	thousand $
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	
POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	Dollars per pound
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	thousand $
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

Variable Name	Variable Type	Description	Unit
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	thousand $
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	
PSHUT	Input	Number of years before economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	thousand $
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	thousand $
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	thousand $
PWP_F	Variable	Cost for a produced water handling plant	thousand $
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	thousand $
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual-use drilling footage for crude oil and natural gas development	ft

Variable Name	Variable Type	Description	Unit
REG_EXP	Variable	Regional exploratory drilling constraints	Mb/y
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	Mb/y
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/y
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/y
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	Mb/y
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/y
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/y
REG_HADG	Variable	Regional historical associated-dissolved (AD) gas	MMcf
REG_HCBM	Variable	Regional historical coalbed methane (CBM)	MMcf
REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	Mb
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	Mb
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	Mb/y
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

Variable Name	Variable Type	Description	Unit
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	Mb
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	thousand $
REM_BASE	Variable	Remaining depreciation base	thousand $
RES_CHR_ FAC	Input	Reservoir characterization cost	$/cumulative barrels of oil equivalent (BOE)
RES_CHR_CHG	Variable	Reservoir characterization cost	$/cumulative BOE
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	Percent
ROYALTY	Variable	Royalty	thousand $
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	Mb
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	Mb
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	thousand $
SFIT	Variable	Alternative minimum tax	thousand $
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	Percent
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	thousand $
STIM	Variable	Stimulation cost	thousand $

Variable Name	Variable Type	Description	Unit
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	thousand $
STIM_W	Variable	Natural gas well stimulation cost	thousand $
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	thousand $
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	Percent
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	Percent
SUCEXPD	Input	Exploratory well dryhole rate by region	Percent
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	Mb
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	Mb
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	thousand $
TANG_FAC_RATE	Input	Percentage of the well costs that are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs that are tangible	Percent
TCI	Variable	Total capital investments	thousand $
TCIADJ	Variable	Adjusted capital investments	thousand $
TCOII	Input	Tax credit on intangible investments	thousand $
TCOTI	Input	Tax credit on tangible investments	thousand $
TDTC	Input	Tangible development tax credit	thousand $
TDTCAB	Input	Tangible development tax credit rate addback	Percent

Variable Name	Variable Type	Description	Unit
TDTCR	Input	Tangible development tax credit rate	Percent
TECH01_FAC	Input	WAG ratio applied to CO2 EOR	
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 CO2 flood	Mb
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	Mb
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	Mb
TECH_HORPRF	Variable	Technical production for horizontal profile	Mb
TECH_INFILL	Variable	Technical production from infill drilling	Mb
TECH_NGL	Variable	Annual technical NGL production	Mb
TECH_OIL	Variable	Annual technical crude oil production	Mb
TECH_PLYFLD	Variable	Technical production from polymer injection	Mb
TECH_PRFMOD	Variable	Technical production from profile modification	Mb
TECH_PRIMARY	Variable	Technical production from primary sources	Mb
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	Mb
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	Mb
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	Mb
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf

Variable Name	Variable Type	Description	Unit
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	Mb
TECH_WTRFLD	Variable	Technical production from waterflood	Mb
TGGLCD	Variable	Total G & G cost	thousand $
TI	Variable	Tangible costs	thousand $
TI_DRL	Variable	Tangible drilling cost	thousand $
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	thousand $
TORECY	Variable	Annual water injection	Mb
TORECY_CST	Variable	Water injection cost	thousand $
TOTHWCAP	Variable	Total horizontal drilling footage constraint	ft
TOTINJ	Variable	Annual water injection	Mb
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	thousand $
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	thousand $
UMPCO2	Input	CO2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas, or lease condensate	Bcf, MMb
UNDRES	Variable	Undiscovered resource	MMb, cf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO2 by region	Bcf
USE_RDR	Input	Use rig-depth rating	
USEAVAIL	Variable	Used annual CO2 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	Mb
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	Percent
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	

Variable Name	Variable Type	Description	Unit
WAT_OAM	Input	Process-specific operating cost for water production	$/b
WATINJ	Variable	Annual water injection	Mb
WATPROD	Variable	Annual water production	Mb
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	Mb
WPROD	Variable	Well level water production	Mb
WRK_W	Variable	Cost for well workover	thousand $
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	Mb
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 cost and constraint calculation was assessed as unit costs per well. The product of the cost equation and cost adjustment factor is the actual cost. The actual cost reflects the influence on the resource, region, and oil or natural gas price. The statistical software included within Microsoft Excel Solver was used for the estimations.

Drilling and completion costs for crude oil

The 2004–2007 Joint Association Survey (JAS) data were used to calculate the equation for drilling and completion costs for crude oil. The data were analyzed at a regional level. The independent variables were depth, raised to powers of 1 and 2. Drilling cost is the cost of drilling on a per-well basis. Depth is also on a per-well basis. The method of estimation used was ordinary least squares. The form of the equation is:

$$DWC\_W_r = A * \exp(-B * DEPTH) + C * (DEPTH + NLAT*LATLEN) + D * (DEPTH + NLAT*LATLEN)^2 + E * \exp(F * DEPTH) \quad (2.B\text{-}1)$$

where

r = region
$A = DNCC\_COEF_{1,1,r}$
$B = DNCC\_COEF_{1,2,r}$
$C = DNCC\_COEF_{1,3,r}$
$D = DNCC\_COEF_{1,4,r}$
$E = DNCC\_COEF_{1,5,r}$
$F = DNCC\_COEF_{1,6,r}$

Table 2-7. Drilling and completion cost equation coefficients for crude oil wells from equation 2-18

Region	A	B	C	D	E	F
1	175011.5284	0.000328495	0.009597636	0.062652682	11748.88602	0.000302173
2	177665.2964	0.000224331	0	0.029365644	32185.29746	0.00024632
3	0	0	57.22884814	0.022822632	0	0
4	152884.4811	0.000308963	0	0.027877593	56715.39157	0.000224376
5	106800.542	0.002999989	0	0.040808966	17576.28773	0.000409701
6	149098.3784	9.3188E-05	8.051230813	0.03228982	282024.3983	0.000135664
7	113994.7702	0	411.2026851	0	70099.74736	0.00018766

Drilling and completion cost for oil—cost adjustment factor

The cost adjustment factor for vertical drilling and completion costs for oil was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

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

East Region:

Regression Statistics	
Multiple R	0.993325966
R Square	0.986696475
Adjusted R Square	0.986411399
Standard Error	0.029280014
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.901997029	2.967332343	3461.175482	4.4887E-131
Residual	140	0.120024694	0.000857319		
Total	143	9.022021723			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309616442	0.009839962	31.46520591	2.3349E-65	0.290162308	0.329070576	0.290162308	0.329070576
β1	0.019837121	0.000434252	45.68110123	5.41725E-86	0.018978581	0.020695661	0.018978581	0.020695661
β2	-0.000142411	5.21769E-06	-27.29392193	6.44605E-58	-0.000152727	-0.000132095	-0.000152727	-0.000132095
β3	3.45898E-07	1.69994E-08	20.34770764	1.18032E-43	3.1229E-07	3.79507E-07	3.1229E-07	3.79507E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.975220111
R Square	0.951054265
Adjusted R Square	0.950005428
Standard Error	0.054224144
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.998414341	2.666138114	906.7701736	1.76449E-91
Residual	140	0.411636098	0.002940258		
Total	143	8.410050438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.404677859	0.01822279	22.2072399	1.01029E-47	0.368650426	0.440705292	0.368650426	0.440705292
β1	0.016335847	0.000804199	20.31319148	1.41023E-43	0.014745903	0.017925792	0.014745903	0.017925792
β2	-0.00010587	9.66272E-06	-10.95654411	1.47204E-20	-0.000124974	-8.67663E-05	-0.000124974	-8.67663E-05
β3	2.40517E-07	3.14814E-08	7.639970947	3.10789E-12	1.78277E-07	3.02758E-07	1.78277E-07	3.02758E-07

Midcontinent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993452577
R Square	0.986948023
Adjusted R Square	0.986668338
Standard Error	0.030207623
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.66004438	3.220014793	3528.781511	1.1799E-131
Residual	140	0.127750066	0.0009125		
Total	143	9.787794446			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.293837119	0.010151698	28.944627	5.92751E-61	0.273766667	0.313907571	0.273766667	0.313907571
β1	0.020183122	0.00044801	45.05064425	3.35207E-85	0.019297383	0.021068861	0.019297383	0.021068861
β2	-0.000142936	5.38299E-06	-26.55334755	1.63279E-56	-0.000153579	-0.000132294	-0.000153579	-0.000132294
β3	3.44926E-07	1.75379E-08	19.66744699	4.04901E-42	3.10253E-07	3.796E-07	3.10253E-07	3.796E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.993622433
R Square	0.987285538
Adjusted R Square	0.987013086
Standard Error	0.029478386
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.446702681	3.148900894	3623.69457	1.8856E-132
Residual	140	0.121656535	0.000868975		
Total	143	9.568359216			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.297270516	0.009906628	30.00723517	7.63744E-63	0.27768458	0.316856451	0.27768458	0.316856451
β1	0.020126228	0.000437194	46.03497443	1.9664E-86	0.019261872	0.020990585	0.019261872	0.020990585
β2	-0.000143079	5.25304E-06	-27.23739215	8.23219E-58	-0.000153465	-0.000132693	-0.000153465	-0.000132693
β3	3.45557E-07	1.71145E-08	20.19080817	2.6538E-43	3.1172E-07	3.79393E-07	3.1172E-07	3.79393E-07

West Coast Region:

Regression Statistics	
Multiple R	0.993362569
R Square	0.986769193
Adjusted R Square	0.986485676
Standard Error	0.030158697
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.496912448	3.165637483	3480.455028	3.0585E-131
Residual	140	0.127336582	0.000909547		
Total	143	9.62424903			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297702178	0.010135256	29.37293095	1.01194E-61	0.277664233	0.317740124	0.277664233	0.317740124
β1	0.020091425	0.000447284	44.91872099	4.92225E-85	0.019207121	0.02097573	0.019207121	0.02097573
β2	-0.000142627	5.37427E-06	-26.53879345	1.74092E-56	-0.000153252	-0.000132001	-0.000153252	-0.000132001
β3	3.44597E-07	1.75095E-08	19.68054067	3.78057E-42	3.0998E-07	3.79214E-07	3.0998E-07	3.79214E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993744864
R Square	0.987528854
Adjusted R Square	0.987261615
Standard Error	0.029293844
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.513146663	3.171048888	3695.304354	4.8762E-133
Residual	140	0.1201381	0.000858129		
Total	143	9.633284764			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.292784596	0.00984461	29.74059899	2.25193E-62	0.273321274	0.312247919	0.273321274	0.312247919
β1	0.020415818	0.000434457	46.99153447	1.31433E-87	0.019556872	0.021274763	0.019556872	0.021274763
β2	-0.000146385	5.22015E-06	-28.04230529	2.6131E-59	-0.000156706	-0.000136065	-0.000156706	-0.000136065
β3	3.5579E-07	1.70074E-08	20.91972526	6.3186E-45	3.22166E-07	3.89415E-07	3.22166E-07	3.89415E-07

Drilling and completion costs for natural gas

The 2004–2007 JAS data were used to calculate the equation for vertical drilling and completion costs for natural gas. The data were analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per-well basis. Depth is also on a per-well basis. The method of estimation used was ordinary least squares. The form of the equation is given below.

$$DWC\_W_r = A * \exp(-B * DEPTH) + C * (DEPTH + NLAT*LATLEN) + D * (DEPTH + NLAT*LATLEN)^2 + E * \exp(F * DEPTH) \quad (2.B\text{-}3)$$

where

$A = DNCC\_COEF_{2,1,r}$

$B = DNCC\_COEF_{2,2,r}$

$C = DNCC\_COEF_{2,3,r}$

$D = DNCC\_COEF_{2,4,r}$

$E = DNCC\_COEF_{2,5,r}$

$F = DNCC\_COEF_{2,6,r}$

Table 2-8. Drilling and completion cost equation coefficients for natural gas wells from equation 2-24

REGION	A	B	C	D	E	F
1	139453.9519	0	17.70277703	0.040091678	57953.91743	2.8256E-05
2	362007.9246	0.000271951	0	0.025535	57768.60381	0.000257353
3	277684.8382	0.00014696	0	0.007866326	160096.0261	0.000204878
4	401334.1702	1.0418E-06	15.43874958	0	140711.327	0.000271092
5	175100	0.00056	0	0.043567666	64577.80553	0.000313095
6	394451.065	0.000214449	0	0.023364998	74723.77447	0.000237271
7	388269.0259	0.000405627	88.01255624	0.046478146	0	0

Drilling and completion cost for gas—cost adjustment factor

The cost adjustment factor for vertical drilling and completion costs for natural gas was calculated using JAS data through 2007. The initial cost was normalized at various prices from $1 to $20 per thousand cubic feet (Mcf). This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per Mcf were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * \text{Natural Gas Price} + \beta 2 * \text{Natural Gas Price}^2 + \beta 3 * \text{Natural Gas Price}^3 \quad (2.B\text{-}4)$$

East Region:

Regression Statistics	
Multiple R	0.988234523
R Square	0.976607472
Adjusted R Square	0.976106203
Standard Error	0.03924461
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001833192	3.000611064	1948.272332	6.4218E-114
Residual	140	0.215619522	0.001540139		
Total	143	9.217452714			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315932281	0.013188706	23.95476038	2.2494E-51	0.289857502	0.34200706	0.289857502	0.34200706
β1	0.195760743	0.005820373	33.63371152	6.11526E-69	0.184253553	0.207267932	0.184253553	0.207267932
β2	-0.013906425	0.000699337	-19.88514708	1.29788E-42	-0.015289053	-0.012523798	-0.015289053	-0.012523798
β3	0.000336178	2.27846E-05	14.75458424	2.61104E-30	0.000291131	0.000381224	0.000291131	0.000381224

Gulf Coast Region:

Regression Statistics	
Multiple R	0.976776879
R Square	0.954093072
Adjusted R Square	0.953109352
Standard Error	0.051120145
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.60369517	2.534565057	969.8828784	1.98947E-93
Residual	140	0.365857688	0.002613269		
Total	143	7.969552858			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343645899	0.017179647	20.00308313	7.02495E-43	0.309680816	0.377610983	0.309680816	0.377610983
β1	0.190338822	0.007581635	25.10524794	1.08342E-53	0.175349523	0.205328121	0.175349523	0.205328121
β2	-0.013965513	0.000910959	-15.33056399	9.3847E-32	-0.015766527	-0.012164498	-0.015766527	-0.012164498
β3	0.000342962	2.96793E-05	11.55560459	4.15963E-22	0.000284285	0.00040164	0.000284285	0.00040164

Midcontinent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.966438524
R Square	0.934003421
Adjusted R Square	0.932589209
Standard Error	0.06631093
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.712149531	2.904049844	660.4406967	2.13407E-82
Residual	140	0.615599523	0.004397139		
Total	143	9.327749054			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.323862308	0.022284725	14.53292844	9.46565E-30	0.279804211	0.367920404	0.279804211	0.367920404
β1	0.193832047	0.009834582	19.70923084	3.2532E-42	0.174388551	0.213275544	0.174388551	0.213275544
β2	-0.013820723	0.001181658	-11.69604336	1.80171E-22	-0.016156924	-0.011484522	-0.016156924	-0.011484522
β3	0.000334693	3.84988E-05	8.693602923	8.44808E-15	0.000258579	0.000410807	0.000258579	0.000410807

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.985593617
R Square	0.971394777
Adjusted R Square	0.970781808
Standard Error	0.0421446
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.444274294	2.814758098	1584.737059	8.3614E-108
Residual	140	0.248663418	0.001776167		
Total	143	8.692937712			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32536782	0.014163288	22.97261928	2.42535E-49	0.29736624	0.353369401	0.29736624	0.353369401
β1	0.194045615	0.006250471	31.04496067	1.21348E-64	0.181688099	0.206403131	0.181688099	0.206403131
β2	-0.01396687	0.000751015	-18.59732564	1.18529E-39	-0.015451667	-0.012482073	-0.015451667	-0.012482073
β3	0.000339698	2.44683E-05	13.88318297	4.22503E-28	0.000291323	0.000388073	0.000291323	0.000388073

West Coast Region:

Regression Statistics	
Multiple R	0.994143406
R Square	0.988321112
Adjusted R Square	0.98807085
Standard Error	0.026802603
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.510960152	2.836986717	3949.147599	4.9307E-135
Residual	140	0.100573131	0.00071838		
Total	143	8.611533284			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325917293	0.009007393	36.18330938	6.29717E-73	0.308109194	0.343725393	0.308109194	0.343725393
β1	0.193657091	0.003975097	48.71757347	1.12458E-89	0.185798111	0.201516072	0.185798111	0.201516072
β2	-0.013893214	0.000477621	-29.08835053	3.2685E-61	-0.014837497	-0.012948932	-0.014837497	-0.012948932
β3	0.000337413	1.5561E-05	21.68318808	1.35414E-46	0.000306648	0.000368178	0.000306648	0.000368178

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.970035104
R Square	0.940968103
Adjusted R Square	0.939703134
Standard Error	0.057035843
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.259587116	2.419862372	743.8663996	8.71707E-86
Residual	140	0.455432229	0.003253087		
Total	143	7.715019345			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.352772153	0.0191677	18.40451098	3.34838E-39	0.31487658	0.390667726	0.31487658	0.390667726
β1	0.189510541	0.008458993	22.40344064	3.85701E-48	0.172786658	0.206234423	0.172786658	0.206234423
β2	-0.014060192	0.001016376	-13.83364754	5.65155E-28	-0.016069622	-0.012050761	-0.016069622	-0.012050761
β3	0.000347364	3.31138E-05	10.49000322	2.34854E-19	0.000281896	0.000412832	0.000281896	0.000412832

Drilling and completion costs for dryholes

The 2004–2007 JAS data were used to calculate the equation for vertical drilling and completion costs for dryholes. The data were analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per-well basis. Depth is also on a per-well basis. The method of estimation used was ordinary least squares. The form of the equation is given bellow.

$$DWC\_W_r = A * \exp(-B * DEPTH) + C * (DEPTH + NLAT*LATLEN)$$

$$+ D * (DEPTH + NLAT*LATLEN)^2 + E * \exp(F * DEPTH) \quad (2.B\text{-}5)$$

where
$A = DNCC\_COEF_{3,1,r}$
$B = DNCC\_COEF_{3,2,r}$
$C = DNCC\_COEF_{3,3,r}$
$D = DNCC\_COEF_{3,4,r}$
$E = DNCC\_COEF_{3,5,r}$
$F = DNCC\_COEF_{3,6,r}$

Table 2-9. Drilling and completion cost equation coefficients for dryhole wells from equations 2-20 and 2-26

REGION	A	B	C	D	E	F
1	373565.4949	0.000335422	0	0.010812916	198571.346	0.000274926
2	145975.4369	0.000298125	5.732481719	0.019485239	139514.304	0.00024177
3	295750.3696	0.000788459	86.14054863	0.013865231	0	0
4	389495.9332	0.000416281	0	0	101481.6339	0.000320498
5	300000	0.000905	0	0.033907497	94160.22038	0.000316633
6	1371262.505	0.000167253	0	0	55899.52234	0.000369903
7	130200	0.003	409.5898966	0.014126494	340333.6789	0.000211981

Drilling and completion cost for dryholes—cost adjustment factor

The cost adjustment factor for vertical drilling and completion costs for dryholes was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$Cost = \beta 0 + \beta 1 * Oil\ Price + \beta 2 * Oil\ Price^2 + \beta 3 * Oil\ Price^3 \quad (2.B\text{-}6)$$

East Region:

Regression Statistics	
Multiple R	0.994846264
R Square	0.989719089
Adjusted R Square	0.989498783
Standard Error	0.026930376
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.774469405	3.258156468	4492.489925	6.5663E-139
Residual	140	0.101534319	0.000725245		
Total	143	9.876003725			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.290689859	0.009050333	32.11924425	1.85582E-66	0.272796865	0.308582854	0.272796865	0.308582854
β1	0.020261651	0.000399405	50.72962235	5.26469E-92	0.019472006	0.021051296	0.019472006	0.021051296
β2	-0.000143294	4.79898E-06	-29.85918012	1.391E-62	-0.000152782	-0.000133806	-0.000152782	-0.000133806
β3	3.45487E-07	1.56352E-08	22.09672004	1.74153E-47	3.14575E-07	3.76399E-07	3.14575E-07	3.76399E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.993347128
R Square	0.986738516
Adjusted R Square	0.986454342
Standard Error	0.031666016
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.44539464	3.481798214	3472.296057	3.5967E-131
Residual	140	0.140383119	0.001002737		
Total	143	10.58577776			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.277940175	0.010641812	26.11774938	1.12431E-55	0.256900742	0.298979608	0.256900742	0.298979608
β1	0.020529977	0.000469639	43.71437232	1.71946E-83	0.019601475	0.021458479	0.019601475	0.021458479
β2	-0.000143466	5.64287E-06	-25.42421447	2.53682E-54	-0.000154622	-0.000132309	-0.000154622	-0.000132309
β3	3.43878E-07	1.83846E-08	18.70465533	6.66256E-40	3.07531E-07	3.80226E-07	3.07531E-07	3.80226E-07

Midcontinent Region:

Regression Statistics	
Multiple R	0.984006541
R Square	0.968268874
Adjusted R Square	0.967588921
Standard Error	0.048034262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.856909541	3.285636514	1424.023848	1.1869E-104
Residual	140	0.323020652	0.00230729		
Total	143	10.17993019			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.289971748	0.016142592	17.96314638	3.67032E-38	0.258056977	0.32188652	0.258056977	0.32188652
β1	0.020266191	0.000712397	28.44789972	4.71502E-60	0.018857744	0.021674637	0.018857744	0.021674637
β2	-0.000143007	8.55969E-06	-16.70702184	3.8001E-35	-0.00015993	-0.000126084	-0.00015993	-0.000126084
β3	3.44462E-07	2.78877E-08	12.35174476	3.63124E-24	2.89326E-07	3.99597E-07	2.89326E-07	3.99597E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993309425
R Square	0.986663613
Adjusted R Square	0.986377833
Standard Error	0.031536315
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.30103457	3.43367819	3452.531986	5.3348E-131
Residual	140	0.139235479	0.000994539		
Total	143	10.44027005			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.278136296	0.010598224	26.24367047	6.42248E-56	0.257183038	0.299089554	0.257183038	0.299089554
β1	0.020381432	0.000467715	43.57656163	2.59609E-83	0.019456733	0.02130613	0.019456733	0.02130613
β2	-0.00014194	5.61976E-06	-25.25738215	5.41293E-54	-0.000153051	-0.00013083	-0.000153051	-0.00013083
β3	3.38578E-07	1.83093E-08	18.49210412	2.08785E-39	3.0238E-07	3.74777E-07	3.0238E-07	3.74777E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.9949703
R Square	0.9899658
Adjusted R Squar	0.9897508
Standard Error	0.0266287
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.79418782	3.2647293	4604.11	1.199E-139
Residual	140	0.09927263	0.0007091		
Total	143	9.89346045			

	Coefficients	Standard Erro	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.2902761	0.00894897	32.436833	5.504E-67	0.27258355	0.3079687	0.2725836	0.3079687
β1	0.0202676	0.00039493	51.319418	1.133E-92	0.01948684	0.0210484	0.0194868	0.0210484
β2	-0.0001433	4.7452E-06	-30.194046	3.595E-63	-0.0001527	-0.0001339	-0.0001527	-0.0001339
β3	3.454E-07	1.546E-08	22.340389	5.253E-48	3.1482E-07	3.76E-07	3.148E-07	3.76E-07

West Coast Region:

Regression Statistics	
Multiple R	0.992483684
R Square	0.985023864
Adjusted R Square	0.984702946
Standard Error	0.032081124
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.477071064	3.159023688	3069.401798	1.7868E-127
Residual	140	0.144087788	0.001029198		
Total	143	9.621158852			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297817853	0.010781315	27.62351924	1.55941E-58	0.276502615	0.31913309	0.276502615	0.31913309
β1	0.020092432	0.000475796	42.22913162	1.54864E-81	0.019151759	0.021033105	0.019151759	0.021033105
β2	-0.000142719	5.71684E-06	-24.96465108	2.06229E-53	-0.000154021	-0.000131416	-0.000154021	-0.000131416
β3	3.44906E-07	1.86256E-08	18.51777816	1.81824E-39	3.08082E-07	3.81729E-07	3.08082E-07	3.81729E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993525621
R Square	0.987093159
Adjusted R Square	0.986816584
Standard Error	0.031179889
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.40915184	3.469717279	3568.986978	5.3943E-132
Residual	140	0.136105966	0.000972185		
Total	143	10.5452578			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281568556	0.010478442	26.87122338	4.04796E-57	0.260852113	0.302284998	0.260852113	0.302284998
β1	0.020437386	0.000462429	44.19569691	4.11395E-84	0.019523138	0.021351633	0.019523138	0.021351633
β2	-0.000142671	5.55624E-06	-25.67758357	8.07391E-55	-0.000153656	-0.000131686	-0.000153656	-0.000131686
β3	3.42012E-07	1.81024E-08	18.89319503	2.43032E-40	3.06223E-07	3.77802E-07	3.06223E-07	3.77802E-07

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 Indexes database provided by EIA. The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data were analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

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

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 so 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

Midcontinent, 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 Mountain, 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 region 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

Cost to equip a primary producer—cost adjustment factor

The cost adjustment factor for the cost to equip a primary producer was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3 \qquad (2.B\text{-}8)$$

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

Regression Statistics	
Multiple R	0.994410537
R Square	0.988852316
Adjusted R Square	0.988613437
Standard Error	0.026443679
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.683975313	2.894658438	4139.554242	1.896E-136
Residual	140	0.097897541	0.000699268		
Total	143	8.781872854			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31969898	0.008886772	35.97470366	1.30857E-72	0.302129355	0.337268604	0.302129355	0.337268604
β1	0.01951727	0.000392187	49.76527469	6.72079E-91	0.018741896	0.020292644	0.018741896	0.020292644
β2	-0.000139868	4.71225E-06	-29.68181785	2.86084E-62	-0.000149185	-0.000130552	-0.000149185	-0.000130552
β3	3.39583E-07	1.53527E-08	22.11882142	1.56166E-47	3.0923E-07	3.69936E-07	3.0923E-07	3.69936E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994238324
R Square	0.988509845
Adjusted R Square	0.988263627
Standard Error	0.026795052
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.647535343	2.882511781	4014.781289	1.5764E-135
Residual	140	0.100516472	0.000717975		
Total	143	8.748051814			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.320349357	0.009004856	35.57517997	5.36201E-72	0.302546274	0.33815244	0.302546274	0.33815244
β1	0.019534419	0.000397398	49.15583863	3.4382E-90	0.018748742	0.020320096	0.018748742	0.020320096
β2	-0.000140302	4.77487E-06	-29.38344709	9.69188E-62	-0.000149742	-0.000130862	-0.000149742	-0.000130862
β3	3.41163E-07	1.55567E-08	21.9303828	3.96368E-47	3.10407E-07	3.7192E-07	3.10407E-07	3.7192E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994150147
R Square	0.988334515
Adjusted R Square	0.98808454
Standard Error	0.026852947
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.552894405	2.850964802	3953.738464	4.5499E-135
Residual	140	0.100951309	0.000721081		
Total	143	8.653845713			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.322462264	0.009024312	35.73261409	3.07114E-72	0.304620715	0.340303814	0.304620715	0.340303814
β1	0.019485751	0.000398256	48.9276546	6.36471E-90	0.018698377	0.020273125	0.018698377	0.020273125
β2	-0.000140187	4.78518E-06	-29.29612329	1.3875E-61	-0.000149648	-0.000130727	-0.000149648	-0.000130727
β3	3.41143E-07	1.55903E-08	21.88177944	5.04366E-47	3.1032E-07	3.71966E-07	3.1032E-07	3.71966E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.99407047
R Square	0.988176099
Adjusted R Square	0.98792273
Standard Error	0.026915882
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.476544403	2.825514801	3900.141282	1.1696E-134
Residual	140	0.101425062	0.000724465		
Total	143	8.577969465			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.324216701	0.009045462	35.84302113	2.08007E-72	0.306333337	0.342100066	0.306333337	0.342100066
β1	0.019446254	0.00039919	48.71430741	1.1346E-89	0.018657034	0.020235473	0.018657034	0.020235473
β2	-0.000140099	4.7964E-06	-29.20929598	1.98384E-61	-0.000149582	-0.000130617	-0.000149582	-0.000130617
β3	3.41157E-07	1.56268E-08	21.8315363	6.47229E-47	3.10262E-07	3.72052E-07	3.10262E-07	3.72052E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.994533252
R Square	0.98909639
Adjusted R Square	0.988862741
Standard Error	0.026511278
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.92601569	2.975338563	4233.261276	4.0262E-137
Residual	140	0.098398698	0.000702848		
Total	143	9.024414388			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.314154129	0.008909489	35.26062149	1.64245E-71	0.296539591	0.331768668	0.296539591	0.331768668
β1	0.019671366	0.000393189	50.03029541	3.32321E-91	0.01889401	0.020448722	0.01889401	0.020448722
β2	-0.000140565	4.7243E-06	-29.75371308	2.13494E-62	-0.000149906	-0.000131225	-0.000149906	-0.000131225
β3	3.40966E-07	1.53919E-08	22.15229024	1.32417E-47	3.10535E-07	3.71397E-07	3.10535E-07	3.71397E-07

Primary workover costs

Primary workover costs were calculated using an average from 2004–2007 data from the most recent Cost and Indexes database provided by EIA. Workover costs consist of the total of workover rig services, remedial services, equipment repair, and other costs. The data were analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

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

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 so zero.

Rocky Mountain, applied to OLOGSS regions 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

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

Midcontinent, 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

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

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

Primary workover costs—cost adjustment factor

The cost adjustment factor for primary workover costs was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3 \qquad (2.B\text{-}10)$$

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

Regression Statistics	
Multiple R	0.994400682
R Square	0.988832717
Adjusted R Square	0.988593418
Standard Error	0.02694729
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001886791	3.00062893	4132.207262	2.1441E-136
Residual	140	0.101661902	0.000726156		
Total	143	9.103548693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312539579	0.009056017	34.51181296	2.43715E-70	0.294635346	0.330443812	0.294635346	0.330443812
β1	0.019707131	0.000399656	49.31028624	2.26953E-90	0.018916991	0.020497272	0.018916991	0.020497272
β2	-0.000140623	4.802E-06	-29.28428914	1.45673E-61	-0.000150117	-0.000131129	-0.000150117	-0.000131129
β3	3.40873E-07	1.5645E-08	21.78791181	8.03921E-47	3.09942E-07	3.71804E-07	3.09942E-07	3.71804E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994469633
R Square	0.98896985
Adjusted R Square	0.98873349
Standard Error	0.026569939
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.861572267	2.953857422	4184.161269	9.0291E-137
Residual	140	0.098834632	0.000705962		
Total	143	8.960406899			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315903453	0.008929203	35.37868321	1.07799E-71	0.298249938	0.333556967	0.298249938	0.333556967
β1	0.019629392	0.000394059	49.81332121	5.91373E-91	0.018850316	0.020408468	0.018850316	0.020408468
β2	-0.000140391	4.73475E-06	-29.65123432	3.24065E-62	-0.000149752	-0.00013103	-0.000149752	-0.00013103
β3	3.40702E-07	1.5426E-08	22.08625878	1.83379E-47	3.10204E-07	3.712E-07	3.10204E-07	3.712E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994481853
R Square	0.988994155
Adjusted R Square	0.988758316
Standard Error	0.026752366
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.003736634	3.001245545	4193.504662	7.7373E-137
Residual	140	0.100196473	0.000715689		
Total	143	9.103933107			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312750341	0.00899051	34.78671677	9.00562E-71	0.294975619	0.330525063	0.294975619	0.330525063
β1	0.019699787	0.000396765	49.6510621	9.11345E-91	0.018915362	0.020484212	0.018915362	0.020484212
β2	-0.000140541	4.76726E-06	-29.480463	6.51147E-62	-0.000149966	-0.000131116	-0.000149966	-0.000131116
β3	3.40661E-07	1.55319E-08	21.93302302	3.91217E-47	3.09954E-07	3.71368E-07	3.09954E-07	3.71368E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.949969362
R Square	0.902441789
Adjusted R Square	0.900351256
Standard Error	0.090634678
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.63829925	3.546099748	431.6802228	1.59892E-70
Residual	140	1.150050289	0.008214645		
Total	143	11.78834953			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281549378	0.030459064	9.243533578	3.55063E-16	0.221330174	0.341768582	0.221330174	0.341768582
β1	0.020360006	0.001344204	15.14651492	2.70699E-31	0.017702443	0.02301757	0.017702443	0.02301757
β2	-0.000140998	1.61511E-05	-8.729925387	6.86299E-15	-0.000172929	-0.000109066	-0.000172929	-0.000109066
β3	3.36972E-07	5.26206E-08	6.403797584	2.14112E-09	2.32938E-07	4.41006E-07	2.32938E-07	4.41006E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.994382746
R Square	0.988797046
Adjusted R Square	0.988556983
Standard Error	0.026729324
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.828330392	2.942776797	4118.9013	2.6803E-136
Residual	140	0.100023944	0.000714457		
Total	143	8.928354335			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316566704	0.008982767	35.24155917	1.75819E-71	0.298807292	0.334326116	0.298807292	0.334326116
β1	0.019613748	0.000396423	49.47682536	1.45204E-90	0.018829998	0.020397497	0.018829998	0.020397497
β2	-0.000140368	4.76315E-06	-29.46957335	6.80842E-62	-0.000149785	-0.000130951	-0.000149785	-0.000130951
β3	3.40752E-07	1.55185E-08	21.95777375	3.46083E-47	3.10071E-07	3.71433E-07	3.10071E-07	3.71433E-07

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 Indexes database provided by EIA. Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data were 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:

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

where Cost = PSW_W

β0 = PSWK

β1 = PSWA

β2 = PSWB

β3 = 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.

Rocky Mountain, 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

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

Midcontinent, 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

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

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 primary to secondary well—cost adjustment factor

The cost adjustment factor for the cost to convert a primary to secondary well was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$Cost = \beta0 + \beta1 * Oil\ Price + \beta2 * Oil\ Price^2 + \beta3 * Oil\ Price^3 \qquad (2.B\text{-}12)$$

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

Regression Statistics	
Multiple R	0.994210954
R Square	0.988455421
Adjusted R Square	0.988208037
Standard Error	0.032636269
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.7675639	4.255854635	3995.634681	2.1943E-135
Residual	140	0.149117649	0.001065126		
Total	143	12.91668155			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.386844292	0.010967879	35.27065592	1.58464E-71	0.365160206	0.408528378	0.365160206	0.408528378
β1	0.023681158	0.000484029	48.92509151	6.40898E-90	0.022724207	0.024638109	0.022724207	0.024638109
β2	-0.000169861	5.81577E-06	-29.207048	2.00231E-61	-0.00018136	-0.000158363	-0.00018136	-0.000158363
β3	4.12786E-07	1.89479E-08	21.78527316	8.14539E-47	3.75325E-07	4.50247E-07	3.75325E-07	4.50247E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.965088368
R Square	0.931395559
Adjusted R Square	0.929925464
Standard Error	0.077579302
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.43935934	3.813119781	633.5614039	3.21194E-81
Residual	140	0.842596733	0.006018548		
Total	143	12.28195608			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.403458143	0.02607162	15.4749932	4.09637E-32	0.351913151	0.455003136	0.351913151	0.455003136
β1	0.023030837	0.00115058	20.01672737	6.5441E-43	0.02075608	0.025305595	0.02075608	0.025305595
β2	-0.000167719	1.38246E-05	-12.13194348	1.34316E-23	-0.000195051	-0.000140387	-0.000195051	-0.000140387
β3	4.10451E-07	4.5041E-08	9.112847285	7.57277E-16	3.21403E-07	4.995E-07	3.21403E-07	4.995E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.930983781
R Square	0.866730801
Adjusted R Square	0.863875032
Standard Error	0.115716747
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19199867	4.063999556	303.5017657	4.7623E-61
Residual	140	1.874651162	0.013390365		
Total	143	14.06664983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.39376891	0.038888247	10.12565341	2.02535E-18	0.316884758	0.470653063	0.316884758	0.470653063
β1	0.023409924	0.001716196	13.6405849	1.759E-27	0.020016911	0.026802936	0.020016911	0.026802936
β2	-0.000169013	2.06207E-05	-8.196307608	1.41642E-13	-0.000209782	-0.000128245	-0.000209782	-0.000128245
β3	4.11972E-07	6.71828E-08	6.132113904	8.35519E-09	2.79148E-07	5.44796E-07	2.79148E-07	5.44796E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.930623851
R Square	0.866060752
Adjusted R Square	0.863190626
Standard Error	0.117705607
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.5418858	4.180628599	301.7500036	6.76263E-61
Residual	140	1.939645392	0.01385461		
Total	143	14.48153119			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.363067907	0.039556632	9.178433366	5.17966E-16	0.284862323	0.441273492	0.284862323	0.441273492
β1	0.024133277	0.001745693	13.82446554	5.96478E-28	0.020681947	0.027584606	0.020681947	0.027584606
β2	-0.000175479	2.09751E-05	-8.366057262	5.44112E-14	-0.000216948	-0.00013401	-0.000216948	-0.00013401
β3	4.28328E-07	6.83375E-08	6.267838182	4.24825E-09	2.93221E-07	5.63435E-07	2.93221E-07	5.63435E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.930187107
R Square	0.865248054
Adjusted R Square	0.862360512
Standard Error	0.116469162
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19426209	4.06475403	299.6486777	1.03233E-60
Residual	140	1.899109212	0.013565066		
Total	143	14.0933713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.393797507	0.039141107	10.06097011	2.96602E-18	0.316413437	0.471181577	0.316413437	0.471181577
β1	0.023409194	0.001727356	13.55204156	2.96327E-27	0.01999412	0.026824269	0.01999412	0.026824269
β2	-0.000168995	2.07548E-05	-8.142483197	1.91588E-13	-0.000210029	-0.000127962	-0.000210029	-0.000127962
β3	4.11911E-07	6.76196E-08	6.091589926	1.02095E-08	2.78223E-07	5.45599E-07	2.78223E-07	5.45599E-07

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 Indexes database provided by EIA. Conversion costs for a production to an injection well consist of tubing replacement, distribution lines, and header costs. The data were 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 NPC EOR study of 1984. The independent variable is depth. The form of the equation is given below:

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

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 so 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

Midcontinent, 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 Mountain, 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

Cost to convert a producer to an injector—cost adjustment factor

The cost adjustment factor for the cost to convert a producer to an injector was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

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

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

Regression Statistics	
Multiple R	0.99432304
R Square	0.988678308
Adjusted R Square	0.9884357
Standard Error	0.026700062
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.715578807	2.905192936	4075.214275	5.6063E-136
Residual	140	0.099805061	0.000712893		
Total	143	8.815383869			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318906241	0.008972933	35.54091476	6.05506E-72	0.301166271	0.336646211	0.301166271	0.336646211
β1	0.019564167	0.000395989	49.40584281	1.75621E-90	0.018781276	0.020347059	0.018781276	0.020347059
β2	-0.000140323	4.75794E-06	-29.49235038	6.20216E-62	-0.00014973	-0.000130916	-0.00014973	-0.000130916
β3	3.40991E-07	1.55015E-08	21.9972576	2.84657E-47	3.10343E-07	3.71638E-07	3.10343E-07	3.71638E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994644466
R Square	0.989317613
Adjusted R Square	0.989088705
Standard Error	0.025871111
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.678119686	2.892706562	4321.895164	9.5896E-138
Residual	140	0.093704013	0.000669314		
Total	143	8.771823699			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316208692	0.008694352	36.36943685	3.2883E-73	0.299019491	0.333397893	0.299019491	0.333397893
β1	0.01974618	0.000383695	51.46325116	7.80746E-93	0.018987594	0.020504765	0.018987594	0.020504765
β2	-0.000142963	4.61022E-06	-31.00997536	1.39298E-64	-0.000152077	-0.000133848	-0.000152077	-0.000133848
β3	3.4991E-07	1.50202E-08	23.29589312	5.12956E-50	3.20214E-07	3.79606E-07	3.20214E-07	3.79606E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994321224
R Square	0.988674696
Adjusted R Square	0.988432011
Standard Error	0.026701262
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.713550392	2.904516797	4073.899599	5.7329E-136
Residual	140	0.099814034	0.000712957		
Total	143	8.813364425			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318954549	0.008973336	35.54470092	5.97425E-72	0.301213782	0.336695317	0.301213782	0.336695317
β1	0.019563077	0.000396007	49.40087012	1.77978E-90	0.018780151	0.020346004	0.018780151	0.020346004
β2	-0.000140319	4.75815E-06	-29.49027089	6.25518E-62	-0.000149726	-0.000130912	-0.000149726	-0.000130912
β3	3.40985E-07	1.55022E-08	21.99592439	2.8654E-47	3.10337E-07	3.71634E-07	3.10337E-07	3.71634E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994322163
R Square	0.988676564
Adjusted R Square	0.988433919
Standard Error	0.026700311
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.714383869	2.904794623	4074.579587	5.667E-136
Residual	140	0.099806922	0.000712907		
Total	143	8.814190792			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318944377	0.008973016	35.54483358	5.97144E-72	0.301204242	0.336684512	0.301204242	0.336684512
β1	0.019563226	0.000395993	49.40300666	1.76961E-90	0.018780328	0.020346125	0.018780328	0.020346125
β2	-0.000140317	4.75798E-06	-29.49085218	6.24031E-62	-0.000149724	-0.00013091	-0.000149724	-0.00013091
β3	3.40976E-07	1.55017E-08	21.99610109	2.8629E-47	3.10328E-07	3.71624E-07	3.10328E-07	3.71624E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.994041278
R Square	0.988118061
Adjusted R Square	0.987863448
Standard Error	0.027307293
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.681741816	2.893913939	3880.863048	1.6477E-134
Residual	140	0.104396354	0.000745688		
Total	143	8.78613817			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31978359	0.009177001	34.84619603	7.26644E-71	0.301640166	0.337927015	0.301640166	0.337927015
β1	0.019531533	0.000404995	48.22662865	4.2897E-89	0.018730837	0.02033223	0.018730837	0.02033223
β2	-0.000140299	4.86615E-06	-28.83170535	9.47626E-61	-0.00014992	-0.000130679	-0.00014992	-0.000130679
β3	3.41616E-07	1.58541E-08	21.54755837	2.66581E-46	3.10272E-07	3.7296E-07	3.10272E-07	3.7296E-07

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 Indexes database provided by EIA. Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data were 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 NPC EOR study of 1984. The independent variable is depth. The form of the equation is:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}15)$$

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 so 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

Midcontinent, 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 Mountain, 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

Facilities upgrade costs for oil wells—cost adjustment factor

The cost adjustment factor for facilities upgrade costs for oil wells was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3 \qquad (2.B\text{-}16)$$

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

Regression Statistics	
Multiple R	0.994217662
R Square	0.988468759
Adjusted R Square	0.988221661
Standard Error	0.026793237
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615198936	2.871732979	4000.310244	2.0238E-135
Residual	140	0.100502859	0.000717878		
Total	143	8.715701795			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321111529	0.009004246	35.66223488	3.93903E-72	0.303309651	0.338913406	0.303309651	0.338913406
β1	0.019515262	0.000397371	49.11095778	3.88014E-90	0.018729638	0.020300885	0.018729638	0.020300885
β2	-0.00014023	4.77454E-06	-29.37035185	1.02272E-61	-0.00014967	-0.00013079	-0.00014967	-0.00013079
β3	3.4105E-07	1.55556E-08	21.92459665	4.07897E-47	3.10296E-07	3.71805E-07	3.10296E-07	3.71805E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994217643
R Square	0.988468723
Adjusted R Square	0.988221624
Standard Error	0.026793755
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615504692	2.871834897	4000.297521	2.0242E-135
Residual	140	0.100506746	0.000717905		
Total	143	8.716011438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321091731	0.00900442	35.65934676	3.9795E-72	0.30328951	0.338893953	0.30328951	0.338893953
β1	0.019515756	0.000397379	49.11125155	3.87707E-90	0.018730117	0.020301395	0.018730117	0.020301395
β2	-0.000140234	4.77464E-06	-29.37065243	1.02145E-61	-0.000149674	-0.000130794	-0.000149674	-0.000130794
β3	3.41061E-07	1.55559E-08	21.92486379	4.07357E-47	3.10306E-07	3.71816E-07	3.10306E-07	3.71816E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994881087
R Square	0.989788377
Adjusted R Square	0.989569556
Standard Error	0.025598703
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.892246941	2.964082314	4523.289171	4.0903E-139
Residual	140	0.0917411	0.000655294		
Total	143	8.983988041			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305413562	0.008602806	35.50162345	6.96151E-72	0.288405354	0.32242177	0.288405354	0.32242177
β1	0.019922983	0.000379655	52.47659224	5.82045E-94	0.019172385	0.020673581	0.019172385	0.020673581
β2	-0.000143398	4.56168E-06	-31.43544891	2.62249E-65	-0.000152417	-0.00013438	-0.000152417	-0.00013438
β3	3.48664E-07	1.48621E-08	23.45993713	2.3433E-50	3.1928E-07	3.78047E-07	3.1928E-07	3.78047E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994218671
R Square	0.988470767
Adjusted R Square	0.988223712
Standard Error	0.026793398
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.616820316	2.872273439	4001.015021	1.9993E-135
Residual	140	0.100504067	0.000717886		
Total	143	8.717324383			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32105584	0.0090043	35.65583598	4.02926E-72	0.303253856	0.338857825	0.303253856	0.338857825
β1	0.019516684	0.000397373	49.11424236	3.84594E-90	0.018731056	0.020302312	0.018731056	0.020302312
β2	-0.00014024	4.77457E-06	-29.37236101	1.01431E-61	-0.00014968	-0.000130801	-0.00014968	-0.000130801
β3	3.4108E-07	1.55557E-08	21.92639924	4.0427E-47	3.10326E-07	3.71835E-07	3.10326E-07	3.71835E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.994682968
R Square	0.989394207
Adjusted R Square	0.98916694
Standard Error	0.025883453
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.749810675	2.916603558	4353.444193	5.7951E-138
Residual	140	0.093793438	0.000669953		
Total	143	8.843604113			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320979436	0.0086985	36.90055074	5.22609E-74	0.303782034	0.338176837	0.303782034	0.338176837
β1	0.019117244	0.000383878	49.80033838	6.12166E-91	0.018358297	0.019876191	0.018358297	0.019876191
β2	-0.000134273	4.61242E-06	-29.11109331	2.97526E-61	-0.000143392	-0.000125154	-0.000143392	-0.000125154
β3	3.21003E-07	1.50274E-08	21.36117616	6.78747E-46	2.91293E-07	3.50713E-07	2.91293E-07	3.50713E-07

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 Indexes database provided by EIA. Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data were analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in thousand cubic feet. The form of the equation is:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \quad (2.B\text{-}17)$$

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

Midcontinent, 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 Mountain, 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

Gas well facilities costs—cost adjustment factor

The cost adjustment factor for natural gas well facilities cost was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $1 to $20 per Mcf. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per Mcf were then calculated. The cost factor equation was then estimated using the differentials. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Natural Gas Price} + \beta2 * \text{Natural Gas Price}^2 + \beta3 * \text{Natural Gas Price}^3 \qquad (2.B\text{-}18)$$

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

Regression Statistics	
Multiple R	0.995733794
R Square	0.991485789
Adjusted R Square	0.991303341
Standard Error	0.025214281
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.3648558	3.454951933	5434.365566	1.2179E-144
Residual	140	0.089006392	0.00063576		
Total	143	10.45386219			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.276309237	0.008473615	32.60818851	2.86747E-67	0.259556445	0.293062029	0.259556445	0.293062029
β1	0.20599743	0.003739533	55.08640551	8.89871E-97	0.198604173	0.213390688	0.198604173	0.213390688
β2	-0.014457925	0.000449317	-32.17753015	1.48375E-66	-0.015346249	-0.0135696	-0.015346249	-0.0135696
β3	0.000347281	1.46389E-05	23.72318475	6.71084E-51	0.000318339	0.000376223	0.000318339	0.000376223

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.99551629
R Square	0.991052684
Adjusted R Square	0.990860956
Standard Error	0.025683748
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.22936837	3.409789455	5169.05027	3.9254E-143
Residual	140	0.092351689	0.000659655		
Total	143	10.32172006			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.280854163	0.008631386	32.5387085	3.73403E-67	0.263789449	0.297918878	0.263789449	0.297918878
β1	0.204879431	0.00380916	53.78599024	2.17161E-95	0.197348518	0.212410345	0.197348518	0.212410345
β2	-0.014391989	0.000457683	-31.44530093	2.52353E-65	-0.015296854	-0.013487125	-0.015296854	-0.013487125
β3	0.000345909	1.49115E-05	23.19753012	8.21832E-50	0.000316428	0.00037539	0.000316428	0.00037539

Midcontinent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.995511275
R Square	0.991042698
Adjusted R Square	0.990850756
Standard Error	0.025690919
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.22356717	3.407855722	5163.235345	4.2442E-143
Residual	140	0.092403264	0.000660023		
Total	143	10.31597043			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.280965064	0.008633796	32.5424714	3.68097E-67	0.263895586	0.298034543	0.263895586	0.298034543
β1	0.204856879	0.003810223	53.7650588	2.28751E-95	0.197323863	0.212389895	0.197323863	0.212389895
β2	-0.014391983	0.000457811	-31.43650889	2.61165E-65	-0.0152971	-0.013486865	-0.0152971	-0.013486865
β3	0.000345929	1.49156E-05	23.19242282	8.42221E-50	0.00031644	0.000375418	0.00031644	0.000375418

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.995452965
R Square	0.990926606
Adjusted R Square	0.990732176
Standard Error	0.025768075
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.15228252	3.384094173	5096.576002	1.0453E-142
Residual	140	0.092959113	0.000663994		
Total	143	10.24524163			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.282511839	0.008659725	32.62364879	2.704E-67	0.265391097	0.299632581	0.265391097	0.299632581
β1	0.204502598	0.003821666	53.51137044	4.3021E-95	0.196946958	0.212058237	0.196946958	0.212058237
β2	-0.014382652	0.000459186	-31.32206064	4.08566E-65	-0.015290487	-0.013474816	-0.015290487	-0.013474816
β3	0.000345898	1.49604E-05	23.12086258	1.18766E-49	0.00031632	0.000375475	0.00031632	0.000375475

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 Indexes database provided by 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 were analyzed on a regional level. The independent variable is depth. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}19)$$

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 so 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

Midcontinent, 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 Mountain, 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 oil wells—cost adjustment factor

The cost adjustment factor of the fixed annual cost for oil wells was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3 \quad (2.B\text{-}20)$$

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

Regression Statistics	
Multiple R	0.994014283
R Square	0.988064394
Adjusted R Square	0.987808631
Standard Error	0.026960479
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.424110153	2.808036718	3863.203308	2.2587E-134
Residual	140	0.101761442	0.000726867		
Total	143	8.525871595			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325522735	0.00906045	35.9278779	1.54278E-72	0.30760974	0.343435731	0.30760974	0.343435731
β1	0.019415379	0.000399851	48.55651174	1.74247E-89	0.018624852	0.020205906	0.018624852	0.020205906
β2	-0.000139999	4.80435E-06	-29.14014276	2.63883E-61	-0.000149498	-0.000130501	-0.000149498	-0.000130501
β3	3.41059E-07	1.56527E-08	21.78917295	7.98896E-47	3.10113E-07	3.72006E-07	3.10113E-07	3.72006E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.972995979
R Square	0.946721175
Adjusted R Square	0.945579485
Standard Error	0.052710031
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.91165462	2.303884873	829.2285185	6.67464E-89
Residual	140	0.388968632	0.002778347		
Total	143	7.300623252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305890757	0.01771395	17.26835352	1.6689E-36	0.270869326	0.340912188	0.270869326	0.340912188
β1	0.019637228	0.000781743	25.11979642	1.01374E-53	0.01809168	0.021182776	0.01809168	0.021182776
β2	-0.000147609	9.39291E-06	-15.71490525	1.03843E-32	-0.000166179	-0.000129038	-0.000166179	-0.000129038
β3	3.60127E-07	3.06024E-08	11.76795581	1.17387E-22	2.99625E-07	4.2063E-07	2.99625E-07	4.2063E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993998856
R Square	0.988033725
Adjusted R Square	0.987777305
Standard Error	0.02698784
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.419321124	2.806440375	3853.182417	2.7032E-134
Residual	140	0.10196809	0.000728344		
Total	143	8.521289214			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32545185	0.009069645	35.88363815	1.80273E-72	0.307520675	0.343383025	0.307520675	0.343383025
β1	0.019419103	0.000400257	48.51658921	1.94263E-89	0.018627774	0.020210433	0.018627774	0.020210433
β2	-0.000140059	4.80922E-06	-29.12303298	2.83205E-61	-0.000149567	-0.000130551	-0.000149567	-0.000130551
β3	3.41232E-07	1.56686E-08	21.77807458	8.44228E-47	3.10254E-07	3.72209E-07	3.10254E-07	3.72209E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.977862049
R Square	0.956214186
Adjusted R Square	0.955275919
Standard Error	0.050111949
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.677722068	2.559240689	1019.127536	7.26235E-95
Residual	140	0.351569047	0.002511207		
Total	143	8.029291115			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343679311	0.016840828	20.40750634	8.67459E-44	0.310384089	0.376974533	0.310384089	0.376974533
β1	0.020087054	0.000743211	27.02739293	2.04852E-57	0.018617686	0.021556422	0.018617686	0.021556422
β2	-0.000153877	8.92993E-06	-17.23164844	2.04504E-36	-0.000171532	-0.000136222	-0.000171532	-0.000136222
β3	3.91397E-07	2.9094E-08	13.45286338	5.31787E-27	3.33877E-07	4.48918E-07	3.33877E-07	4.48918E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.993729589
R Square	0.987498496
Adjusted R Square	0.987230606
Standard Error	0.027203598
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.183798235	2.727932745	3686.217436	5.7808E-133
Residual	140	0.103605007	0.000740036		
Total	143	8.287403242			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.330961672	0.009142153	36.20171926	5.90451E-73	0.312887144	0.3490362	0.312887144	0.3490362
β1	0.019295414	0.000403457	47.82521879	1.29343E-88	0.018497758	0.02009307	0.018497758	0.02009307
β2	-0.000139784	4.84767E-06	-28.83529781	9.33567E-61	-0.000149368	-0.0001302	-0.000149368	-0.0001302
β3	3.4128E-07	1.57939E-08	21.60840729	1.96666E-46	3.10055E-07	3.72505E-07	3.10055E-07	3.72505E-07

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 Indexes database provided by EIA. Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data were analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in thousand cubic feet. The form of the equation is:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \qquad (2.B\text{-}21)$$

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

Midcontinent, applied to OLOGSS regions 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 Mountain, applied to OLOGSS regions 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 natural gas wells—cost adjustment factor

The cost adjustment factor of the fixed annual cost for natural gas wells was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $1 to $20 per Mcf. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per Mcf were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Natural Gas Price} + \beta 2 * \text{Natural Gas Price}^2 + \beta 3 * \text{Natural Gas Price}^3 \qquad (2.B\text{-}22)$$

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

Regression Statistics	
Multiple R	0.994836789
R Square	0.989700237
Adjusted R Square	0.989479527
Standard Error	0.029019958
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.32916798	3.776389326	4484.181718	7.4647E-139
Residual	140	0.117902114	0.000842158		
Total	143	11.44707009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.234219858	0.009752567	24.01622716	1.68475E-51	0.21493851	0.253501206	0.21493851	0.253501206
β1	0.216761767	0.004303953	50.36340872	1.37772E-91	0.20825262	0.225270914	0.20825262	0.225270914
β2	-0.015234638	0.000517134	-29.45972427	7.08872E-62	-0.01625704	-0.014212235	-0.01625704	-0.014212235
β3	0.000365319	1.68484E-05	21.68270506	1.3574E-46	0.000332009	0.000398629	0.000332009	0.000398629

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.995657421
R Square	0.991333701
Adjusted R Square	0.991147994
Standard Error	0.02551118
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.42258156	3.474193854	5338.176859	4.2055E-144
Residual	140	0.091114842	0.00065082		
Total	143	10.5136964			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276966489	0.008573392	32.30535588	9.09319E-67	0.260016432	0.293916546	0.260016432	0.293916546
β1	0.205740933	0.003783566	54.37751691	5.03408E-96	0.198260619	0.213221246	0.198260619	0.213221246
β2	-0.014407802	0.000454608	-31.6927929	9.63037E-66	-0.015306587	-0.013509017	-0.015306587	-0.013509017
β3	0.00034576	1.48113E-05	23.34441529	4.06714E-50	0.000316478	0.000375043	0.000316478	0.000375043

Midcontinent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.995590124
R Square	0.991199695
Adjusted R Square	0.991011117
Standard Error	0.025596313
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.33109303	3.443697678	5256.179662	1.231E-143
Residual	140	0.091723972	0.000655171		
Total	143	10.42281701			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.278704883	0.008602002	32.40000063	6.33409E-67	0.261698262	0.295711504	0.261698262	0.295711504
β1	0.205373482	0.003796192	54.09986358	9.97995E-96	0.197868206	0.212878758	0.197868206	0.212878758
β2	-0.014404563	0.000456125	-31.58028284	1.49116E-65	-0.015306347	-0.013502779	-0.015306347	-0.013502779
β3	0.000345945	1.48607E-05	23.27919988	5.55628E-50	0.000316565	0.000375325	0.000316565	0.000375325

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.995548929
R Square	0.99111767
Adjusted R Square	0.990927334
Standard Error	0.02564864
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.27673171	3.425577238	5207.209824	2.3566E-143
Residual	140	0.092099383	0.000657853		
Total	143	10.3688311			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.279731342	0.008619588	32.45298388	5.17523E-67	0.262689954	0.296772729	0.262689954	0.296772729
β1	0.205151971	0.003803953	53.93125949	1.51455E-95	0.197631352	0.21267259	0.197631352	0.21267259
β2	-0.014402579	0.000457058	-31.51151347	1.94912E-65	-0.015306207	-0.013498952	-0.015306207	-0.013498952
β3	0.00034606	1.48911E-05	23.23943141	6.72233E-50	0.00031662	0.000375501	0.00031662	0.000375501

Fixed annual costs for secondary production

The fixed annual cost for secondary oil production was calculated using an average from 2004–2007 data from the most recent Cost and Indexes database provided by EIA. The data were 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 NPC EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \quad (2.B\text{-}23)$$

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 so 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

Midcontinent, 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 Mountain, 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

Fixed annual costs for secondary production—cost adjustment factor

The cost adjustment factor of the fixed annual costs for secondary production was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3 \quad (2.B\text{-}24)$$

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

Regression Statistics	
Multiple R	0.994022382
R Square	0.988080495
Adjusted R Square	0.987825078
Standard Error	0.026956819
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.433336986	2.811112329	3868.484883	2.0551E-134
Residual	140	0.101733815	0.00072667		
Total	143	8.535070802			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325311813	0.00905922	35.90947329	1.646E-72	0.307401249	0.343222377	0.307401249	0.343222377
β1	0.019419982	0.000399797	48.57461816	1.65866E-89	0.018629562	0.020210402	0.018629562	0.020210402
β2	-0.000140009	4.80369E-06	-29.14604996	2.57525E-61	-0.000149506	-0.000130512	-0.000149506	-0.000130512
β3	3.41057E-07	1.56506E-08	21.79195958	7.87903E-47	3.10115E-07	3.71999E-07	3.10115E-07	3.71999E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.993830992
R Square	0.987700041
Adjusted R Square	0.987436471
Standard Error	0.027165964
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.296590955	2.765530318	3747.383987	1.8532E-133
Residual	140	0.103318541	0.00073799		
Total	143	8.399909496			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321750317	0.009129506	35.24290662	1.74974E-71	0.303700794	0.33979984	0.303700794	0.33979984
β1	0.019369439	0.000402899	48.0752057	6.49862E-89	0.018572887	0.020165992	0.018572887	0.020165992
β2	-0.000140208	4.84096E-06	-28.96291516	5.49447E-61	-0.000149779	-0.000130638	-0.000149779	-0.000130638
β3	3.42483E-07	1.5772E-08	21.71459435	1.15795E-46	3.11301E-07	3.73665E-07	3.11301E-07	3.73665E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994021683
R Square	0.988079106
Adjusted R Square	0.987823658
Standard Error	0.026959706
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.43414809	2.811382697	3868.028528	2.0719E-134
Residual	140	0.101755604	0.000726826		
Total	143	8.535903693			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325281756	0.00906019	35.90231108	1.68802E-72	0.307369274	0.343194238	0.307369274	0.343194238
β1	0.019420568	0.00039984	48.57088177	1.67561E-89	0.018630063	0.020211072	0.018630063	0.020211072
β2	-0.000140009	4.80421E-06	-29.14305099	2.60734E-61	-0.000149507	-0.000130511	-0.000149507	-0.000130511
β3	3.41049E-07	1.56523E-08	21.7891193	7.99109E-47	3.10103E-07	3.71994E-07	3.10103E-07	3.71994E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994023418
R Square	0.988082555
Adjusted R Square	0.987827181
Standard Error	0.026956158
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.434398087	2.811466029	3869.161392	2.0304E-134
Residual	140	0.101728825	0.000726634		
Total	143	8.536126912			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325293493	0.009058998	35.90833165	1.65262E-72	0.307383368	0.343203618	0.307383368	0.343203618
β1	0.019420405	0.000399787	48.57686713	1.64854E-89	0.018630005	0.020210806	0.018630005	0.020210806
β2	-0.000140009	4.80358E-06	-29.14672886	2.56804E-61	-0.000149505	-0.000130512	-0.000149505	-0.000130512
β3	3.41053E-07	1.56502E-08	21.792237	7.86817E-47	3.10111E-07	3.71994E-07	3.10111E-07	3.71994E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.993899019
R Square	0.98783526
Adjusted R Square	0.987574587
Standard Error	0.027222624
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.42499532	2.808331773	3789.557133	8.5487E-134
Residual	140	0.103749972	0.000741071		
Total	143	8.528745292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.327122709	0.009148547	35.75679345	2.81971E-72	0.30903554	0.345209878	0.30903554	0.345209878
β1	0.019283711	0.000403739	47.76280844	1.53668E-88	0.018485497	0.020081925	0.018485497	0.020081925
β2	-0.000138419	4.85106E-06	-28.53379985	3.28809E-60	-0.00014801	-0.000128828	-0.00014801	-0.000128828
β3	3.36276E-07	1.58049E-08	21.27670912	1.03818E-45	3.05029E-07	3.67523E-07	3.05029E-07	3.67523E-07

Lifting costs

Lifting costs for crude oil wells were calculated using an average from 2004–2007 data from the most recent Cost and Indexes database provided by EIA. Lifting costs consist of labor costs for the pumper, chemicals costs, fuel costs, power costs and water costs. The data were analyzed on a regional level. The independent variable is depth. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \quad (2.B\text{-}25)$$

(2.B-26)

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 so 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

Midcontinent, 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 Mountain, applied to OLOGSS regions 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

Lifting costs—cost adjustment factor

The cost adjustment factor for lifting costs was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$Cost = \beta 0 + \beta 1 * Oil\ Price + \beta 2 * Oil\ Price^2 + \beta 3 * Oil\ Price^3 \quad (2.B\text{-}27)$$

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

Regression Statistics	
Multiple R	0.994419415
R Square	0.988869972
Adjusted R Square	0.988631472
Standard Error	0.026749137
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.900010642	2.966670214	4146.195026	1.6969E-136
Residual	140	0.100172285	0.000715516		
Total	143	9.000182927			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314447949	0.008989425	34.97976138	4.49274E-71	0.296675373	0.332220525	0.296675373	0.332220525
β1	0.019667961	0.000396717	49.57683267	1.11119E-90	0.018883631	0.020452291	0.018883631	0.020452291
β2	-0.000140635	4.76668E-06	-29.50377541	5.91881E-62	-0.000150059	-0.000131211	-0.000150059	-0.000131211
β3	3.41221E-07	1.553E-08	21.97170644	3.23018E-47	3.10517E-07	3.71924E-07	3.10517E-07	3.71924E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994725637
R Square	0.989479094
Adjusted R Square	0.989253646
Standard Error	0.026400955
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.177423888	3.059141296	4388.946164	3.302E-138
Residual	140	0.097581462	0.00069701		
Total	143	9.275005349			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307250046	0.008872414	34.62981435	1.58839E-70	0.289708807	0.324791284	0.289708807	0.324791284
β1	0.019843369	0.000391553	50.6786443	6.01683E-92	0.019069248	0.020617491	0.019069248	0.020617491
β2	-0.000141338	4.70464E-06	-30.04217841	6.6318E-63	-0.000150639	-0.000132036	-0.000150639	-0.000132036
β3	3.42235E-07	1.53279E-08	22.32765206	5.59173E-48	3.11931E-07	3.72539E-07	3.11931E-07	3.72539E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994625665
R Square	0.989280214
Adjusted R Square	0.989050504
Standard Error	0.026521235
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.087590035	3.029196678	4306.653909	1.2247E-137
Residual	140	0.09847263	0.000703376		
Total	143	9.186062664			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309274775	0.008912836	34.69993005	1.23231E-70	0.291653621	0.32689593	0.291653621	0.32689593
β1	0.019797213	0.000393337	50.33145871	1.49879E-91	0.019019565	0.020574861	0.019019565	0.020574861
β2	-0.000141221	4.72607E-06	-29.88132995	1.27149E-62	-0.000150565	-0.000131878	-0.000150565	-0.000131878
β3	3.42202E-07	1.53977E-08	22.22423366	9.29272E-48	3.1176E-07	3.72644E-07	3.1176E-07	3.72644E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994686146
R Square	0.98940053
Adjusted R Square	0.989173398
Standard Error	0.026467032
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.154328871	3.051442957	4356.069182	5.5581E-138
Residual	140	0.09807053	0.000700504		
Total	143	9.252399401			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307664081	0.00889462	34.58990756	1.8356E-70	0.29007894	0.325249222	0.29007894	0.325249222
β1	0.019836272	0.000392533	50.53404116	8.79346E-92	0.019060214	0.020612331	0.019060214	0.020612331
β2	-0.000141357	4.71641E-06	-29.97123684	8.83426E-63	-0.000150681	-0.000132032	-0.000150681	-0.000132032
β3	3.42352E-07	1.53662E-08	22.27954719	7.08083E-48	3.11973E-07	3.72732E-07	3.11973E-07	3.72732E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.993880162
R Square	0.987797777
Adjusted R Square	0.987536301
Standard Error	0.027114753
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.332367897	2.777455966	3777.77319	1.0603E-133
Residual	140	0.102929375	0.00073521		
Total	143	8.435297272			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.326854136	0.009112296	35.86957101	1.8943E-72	0.308838638	0.344869634	0.308838638	0.344869634
β1	0.019394839	0.000402139	48.22916512	4.26E-89	0.018599788	0.02018989	0.018599788	0.02018989
β2	-0.000140183	4.83184E-06	-29.01231258	4.47722E-61	-0.000149736	-0.00013063	-0.000149736	-0.00013063
β3	3.41846E-07	1.57423E-08	21.71513554	1.15483E-46	3.10722E-07	3.72969E-07	3.10722E-07	3.72969E-07

Secondary workover costs

Secondary workover costs were calculated using an average from 2004–2007 data from the most recent Cost and Indexes database provided by EIA. Secondary workover costs consist of workover rig services, remedial services, and equipment repair. The data were 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 NPC EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \quad (2.B\text{-}28)$$

where Cost = SWK_W
β0 = OMSWRK
β1 = OMSWRA
β2 = OMSWRB
β3 = 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 so 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

Midcontinent, 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 Mountain, applied to OLOGSS regions 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

Secondary workover costs—cost adjustment factor

The cost adjustment factor for secondary workover costs was calculated using data through 2008 from the Cost and Indexes database provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This step led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3 \quad (2.B\text{-}29)$$

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

Regression Statistics	
Multiple R	0.994646805
R Square	0.989322267
Adjusted R Square	0.989093459
Standard Error	0.026416612
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.051925882	3.017308627	4323.799147	9.3015E-138
Residual	140	0.097697232	0.000697837		
Total	143	9.149623114			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312179978	0.008877675	35.1646082	2.31513E-71	0.294628337	0.329731619	0.294628337	0.329731619
β1	0.019705242	0.000391785	50.29605017	1.64552E-91	0.018930662	0.020479822	0.018930662	0.020479822
β2	-0.000140397	4.70743E-06	-29.82464336	1.6003E-62	-0.000149704	-0.000131091	-0.000149704	-0.000131091
β3	3.4013E-07	1.53369E-08	22.17714344	1.1716E-47	3.09808E-07	3.70452E-07	3.09808E-07	3.70452E-07

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.994648271
R Square	0.989325182
Adjusted R Square	0.989096436
Standard Error	0.026409288
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.049404415	3.016468138	4324.992582	9.1255E-138
Residual	140	0.097643067	0.00069745		
Total	143	9.147047482			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31224985	0.008875214	35.18223288	2.17363E-71	0.294703075	0.329796624	0.294703075	0.329796624
β1	0.019703773	0.000391676	50.30624812	1.60183E-91	0.018929408	0.020478139	0.018929408	0.020478139
β2	-0.000140393	4.70612E-06	-29.83187838	1.55398E-62	-0.000149697	-0.000131088	-0.000149697	-0.000131088
β3	3.40125E-07	1.53327E-08	22.18299399	1.13834E-47	3.09811E-07	3.70439E-07	3.09811E-07	3.70439E-07

Midcontinent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.994391906
R Square	0.988815263
Adjusted R Square	0.98857559
Standard Error	0.027366799
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.269694355	3.089898118	4125.685804	2.3918E-136
Residual	140	0.104851837	0.000748942		
Total	143	9.374546192			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.301399555	0.009196999	32.7715099	1.54408E-67	0.283216594	0.319582517	0.283216594	0.319582517
β1	0.020285999	0.000405877	49.980617	3.79125E-91	0.019483558	0.021088441	0.019483558	0.021088441
β2	-0.000145269	4.87675E-06	-29.78803686	1.85687E-62	-0.00015491	-0.000135627	-0.00015491	-0.000135627
β3	3.51144E-07	1.58886E-08	22.10035946	1.71054E-47	3.19731E-07	3.82556E-07	3.19731E-07	3.82556E-07

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994645783
R Square	0.989320233
Adjusted R Square	0.989091381
Standard Error	0.026422924
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.054508298	3.018169433	4322.966602	9.4264E-138
Residual	140	0.097743924	0.000698171		
Total	143	9.152252223			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.312146343	0.008879797	35.15242029	2.41837E-71	0.294590508	0.329702178	0.294590508	0.329702178
β1	0.019706241	0.000391879	50.28658391	1.68714E-91	0.018931476	0.020481006	0.018931476	0.020481006
β2	-0.000140397	4.70855E-06	-29.81743751	1.64782E-62	-0.000149706	-0.000131088	-0.000149706	-0.000131088
β3	3.4012E-07	1.53406E-08	22.17121727	1.20629E-47	3.09791E-07	3.70449E-07	3.09791E-07	3.70449E-07

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.994644139
R Square	0.989316964
Adjusted R Square	0.989088042
Standard Error	0.026428705
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.05566979	3.018556597	4321.629647	9.6305E-138
Residual	140	0.097786705	0.000698476		
Total	143	9.153456495			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312123671	0.00888174	35.14217734	2.50872E-71	0.294563994	0.329683347	0.294563994	0.329683347
β1	0.019707015	0.000391964	50.27755672	1.72782E-91	0.01893208	0.020481949	0.01893208	0.020481949
β2	-0.0001404	4.70958E-06	-29.81159891	1.68736E-62	-0.000149711	-0.000131089	-0.000149711	-0.000131089
β3	3.40124E-07	1.5344E-08	22.16666321	1.23366E-47	3.09789E-07	3.7046E-07	3.09789E-07	3.7046E-07

Additional cost equations and factors

The model uses several updated cost equations and factors originally developed for the U.S. Department of Energy's (DOE) National Energy Technology Laboratory's (NETL) Comprehensive Oil and Gas Analysis Model (COGAM):

The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs (originally developed based on the 1984 *Enhanced Oil Recovery Study* completed by NPC)
The G&A factors for capitalized and expensed costs
The limits on impurities, such as N_2, CO_2, and H_2S 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 CO_2 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. According to the University of Wyoming, 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 that 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 using data obtained from Denbury Resources, Inc., and other sources. CO_2 capture costs range between $20/ton and $63/ton. The transportation costs were derived using an external economic model that calculates pipeline tariff based on average distance, compression rate, and volume of CO_2 transported.

National and regional drilling footage

National footage equations are used to determine the total drilling footage available for oil, natural gas, and dry wells in two categories: development and exploration. The calculated footage is then allocated to the OLOGSS region using well-category specific regional distributions. In this section, both the national equation and the regional distribution will be provided for each of the six drilling categories.

Oil development footage

The equation for oil drilling footage was estimated for 2000–2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is given by:

$$\text{Oil Footage} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^3 + \beta3 * \text{Oil Price} * \text{Natural Gas Price} \tag{2.B-30}$$

where,

β0 = Intercept
β1 = X Variable 1
β2 = X Variable 2
β3 = X Variable 3

Where oil footage is the total developmental footage for oil wells drilled in the United States measured in thousands of feet. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

National Oil Development Footage Equation

Regression Statistics	
Multiple R	0.8754
R Square	0.7663
Adjusted R Square	0.7225
Standard Error	7289.2277
Observations	20.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3.0000	2787197199.101	929065733.034	17.486	0.000
Residual	16.0000	850125449.849	53132840.616		
Total	19.0000	3637322648.950			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	23726.4078	6520.803	3.639	0.002	9902.923	37549.892	9902.923	37549.892
X Variable 1	839.7889	318.618	2.636	0.018	164.349	1515.229	164.349	1515.229
X Variable 2	0.0416	0.023	1.839	0.085	-0.006	0.090	-0.006	0.090
X Variable 3	-74.6733	34.893	-2.140	0.048	-148.643	-0.703	-148.643	-0.703

The regional drilling distribution for oil was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for developed oil wells.

Table 2-10. Regional distribution for oil development footage

Region	States included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	2.5%
Gulf Coast	AL, FL, LA, MS, TX	19.5%
Midcontinent	AR, KS, MO, NE, OK, TX	9.4%
Southwest	TX, NM	48.8%
Rocky Mountain	CO, NV, UT, WY, NM	5.5%
West Coast	CA, WA	2.1%
Northern Great Plains	MT, ND, SD	12.2%

Natural gas development footage

Natural gas footage is the total developmental footage for natural gas wells drilled in the United States measured in thousands of feet. The equation for natural gas drilling footage was estimated for 2000–2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is given by:

$$\text{Natural Gas Footage} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Natural Gas Price}^2 \tag{2.B-31}$$

where,

β0 = Intercept
β1 = X Variable 1
β2 = X Variable 2

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

National Natural Gas Development Footage Equation

Regression Statistics	
Multiple R	0.9600
R Square	0.9216
Adjusted R Square	0.9124
Standard Error	16146.8030
Observations	20.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2.0000	52118056316.202	26059028158.101	99.951	0.000
Residual	17.0000	4432227190.598	260719246.506		
Total	19.0000	56550283506.800			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	14602.8232	7781.097	1.877	0.078	-1813.856	31019.502	-1813.856	31019.502
X Variable 1	1513.3128	322.721	4.689	0.000	832.431	2194.195	832.431	2194.195
X Variable 2	1131.8266	340.064	3.328	0.004	414.355	1849.298	414.355	1849.298

The regional drilling distribution for natural gas was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for developed natural gas wells.

Table 2-11. Regional distribution for natural gas development footage

Region	States Included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	35.9%
Gulf Coast	AL, FL, LA, MS, TX	23.2%
Midcontinent	AR, KS, MO, NE, OK, TX	13.2%
Southwest	TX, NM	3.9%
Rocky Mountain	CO, NV, UT, WY, NM	23.3%
West Coast	CA, WA	0.2%
Northern Great Plains	MT, ND, SD	0.3%

Dry development footage

Dry footage is the total developmental footage for dry wells drilled in the United States measured in thousands of feet. The equation for dry drilling footage was estimated for 2000−2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is:

$$\text{Dry Footage} = \beta 0 + \beta 1 \text{ Oil Price}^2 + \beta 2 * \text{Oil Price}^3 + \beta 3 * \text{Natural Gas Price} + \beta 4 + \text{Natural Gas Price}^2 \quad (2.B\text{-}32)$$

where,

$\beta 0$ = Intercept
$\beta 1$ = X Variable 1
$\beta 2$ = X Variable 2
$\beta 3$ = X Variable 3
$\beta 4$ = X Variable 4

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

National Dry Development Footage Equation

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.3724
R Square	0.1387
Adjusted R Square	-0.0910
Standard Error	2850.4385
Observations	20.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4.0000	19629082.563	4907270.641	0.604	0.666
Residual	15.0000	121874991.987	8124999.466		
Total	19.0000	141504074.550			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	22111.8088	5591.033	3.955	0.001	10194.804	34028.814	10194.804	34028.814
X Variable 1	0.3689	2.153	0.171	0.866	-4.219	4.957	-4.219	4.957
X Variable 2	0.0002	0.021	0.011	0.991	-0.045	0.046	-0.045	0.046
X Variable 3	-2768.8619	2682.080	-1.032	0.318	-8485.580	2947.856	-8485.580	2947.856
X Variable 4	241.4373	264.236	0.914	0.375	-321.769	804.643	-321.769	804.643

The regional drilling distributions for developmental dry footage was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for developed dry wells.

Table 2-12. Regional distribution for dry development footage

Region	States Included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	2.5%
Gulf Coast	AL, FL, LA, MS, TX	19.5%
Midcontinent	AR, KS, MO, NE, OK, TX	9.4%
Southwest	TX, NM	48.8%
Rocky Mountain	CO, NV, UT, WY, NM	5.5%
West Coast	CA, WA	2.1%
Northern Great Plains	MT, ND, SD	12.2%

Oil exploration footage

Oil footage is the total footage of oil exploration wells drilled in the United States measured in thousands of feet. The equation for oil drilling footage was estimated for 2000–2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is:

$$\text{Oil Footage} = \beta 0 + \beta 1 \text{ Oil Price}^2 + \beta 2 * \text{Natural Gas Price} + \beta 3 * \text{Natural Gas Price} * \text{Oil Price}^2 \quad (2.B\text{-}33)$$

where,

β0 = Intercept
β1 = X Variable 1

β2 = X Variable 2
β3 = X Variable 3

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

National Oil Exploration Footage Equation

Regression Statistics	
Multiple R	0.8554
R Square	0.7317
Adjusted R Square	0.6814
Standard Error	884.2367
Observations	20.0000

ANOVA

	df	SS	MS	F	Significance F
Regression	3.0000	34111589.936	11370529.979	14.543	0.000
Residual	16.0000	12509993.264	781874.579		
Total	19.0000	46621583.200			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	3700.2033	701.868	5.272	0.000	2212.310	5188.097	2212.310	5188.097
X Variable 1	1.6432	0.542	3.032	0.008	0.494	2.792	0.494	2.792
X Variable 2	-356.1698	173.459	-2.053	0.057	-723.886	11.547	-723.886	11.547
X Variable 3	-0.1084	0.071	-1.531	0.145	-0.258	0.042	-0.258	0.042

The regional drilling distribution for oil exploration was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for oil exploration wells.

Table 2-13. Regional distribution for oil exploration footage

Region	States Included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	1.4%
Gulf Coast	AL, FL, LA, MS, TX	6.0%
Midcontinent	AR, KS, MO, NE, OK, TX	26.1%
Southwest	TX, NM	11.3%
Rocky Mountain	CO, NV, UT, WY, NM	7.9%
West Coast	CA, WA	1.0%
Northern Great Plains	MT, ND, SD	46.3%

Natural Gas exploration footage

Natural gas footage is the total footage for natural gas exploration wells drilled in the United States measured in thousands of feet. The equation for natural gas drilling footage was estimated for 2000–2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is:

Natural Gas Footage = β0 + β1 * Oil Price * Natural Gas Price (2.B-34)

where,

β0 = Intercept
β1 = X Variable 1

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

National Gas Exploration Footage Equation

Regression Statistics	
Multiple R	0.9211
R Square	0.8485
Adjusted R Square	0.8401
Standard Error	1,956.4777
Observations	20.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.0000	385,822,486.360	385,822,486.360	100.795	0.000
Residual	18.0000	68,900,492.590	3,827,805.144		
Total	19.0000	454,722,978.950			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	3,048.2708	621.340	4.906	0.000	1,742.883	4,353.658	1,742.883	4,353.658
X Variable 1	23.0787	2.299	10.040	0.000	18.249	27.908	18.249	27.908

The regional drilling distribution for natural gas exploration was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for natural gas exploration wells.

Table 2-14. Regional distribution for natural gas exploration footage

Region	States Included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	77.2%
Gulf Coast	AL, FL, LA, MS, TX	7.0%
Midcontinent	AR, KS, MO, NE, OK, TX	11.4%
Southwest	TX, NM	1.6%
Rocky Mountain	CO, NV, UT, WY, NM	2.5%
West Coast	CA, WA	0.1%
Northern Great Plains	MT, ND, SD	0.3%

Dry exploration footage

Dry footage is the total footage for dry exploration wells drilled in the United States measured in thousands of feet. The equation for dry drilling footage was estimated for 2000–2009. The drilling footage data were compiled from EIA's *Annual Energy Review 2010* and the *2011 Monthly Energy Review*. The form of the estimating equation is:

$$\text{Oil Footage} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * + \text{Oil Price}^3 + \beta4 * \text{Natural Gas Price} + \beta5 * \text{Natural Gas Price}^2 + \beta6 * \text{Natural Gas Price}^3 \quad (2.B\text{-}35)$$

where

β0 = Intercept
β1 = X Variable 1
β2 = X Variable 2
β3 = X Variable 3
β4 = X Variable 4
β5 = X Variable 5
β6 = X Variable 6

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

National Dry Exploration Footage Equation

Regression Statistics	
Multiple R	0.6519
R Square	0.4249
Adjusted R Square	0.1595
Standard Error	3110.0486
Observations	20.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6.0000	92905332.768	15484222.128	1.601	0.224
Residual	13.0000	125741227.232	9672402.095		
Total	19.0000	218646560.000			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	28226.7366	18990.122	1.486	0.161	-12798.927	69252.400	-12798.927	69252.400
X Variable 1	1213.0103	641.922	1.890	0.081	-173.779	2599.799	-173.779	2599.799
X Variable 2	-23.4564	12.533	-1.872	0.084	-50.533	3.620	-50.533	3.620
X Variable 3	0.1356	0.074	1.832	0.090	-0.024	0.296	-0.024	0.296
X Variable 4	-19000.6302	13470.813	-1.411	0.182	-48102.551	10101.291	-48102.551	10101.291
X Variable 5	3125.5097	2686.975	1.163	0.266	-2679.346	8930.366	-2679.346	8930.366
X Variable 6	-165.2930	168.229	-0.983	0.344	-528.730	198.144	-528.730	198.144

The regional drilling distribution for dry exploration was estimated using an updated EIA well-count file. The percentage allocations for each region are calculated using the total footage drilled from 2010 for dry exploration wells.

Table 2-15. Regional distribution for dry exploration footage

Region	States Included	Percentage
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	9.1%
Gulf Coast	AL, FL, LA, MS, TX	32.7%
Midcontinent	AR, KS, MO, NE, OK, TX	39.4%
Southwest	TX, NM	8.6%
Rocky Mountain	CO, NV, UT, WY, NM	5.6%
West Coast	CA, WA	1.2%
Northern Great Plains	MT, ND, SD	3.4%

Regional rig-depth rating

The regional rig-depth ratings were determined using historical rig-count data between 2005 and 2010 from Smith Bits. The depth rating was calculated for each rig, which was classified as either oil or natural gas, and it was assigned to a particular OLOGSS region.

The percentages are applied to the regional drilling footage available to determine the footage that can be drilled in each of the depth categories.

Table 2-16. Regional rig-depth ratings for oil

	East	Gulf Coast	Midcontinent	Southeast	Rocky Mountain	West Coast	Northern Great Plains
0 - 2,500 ft	100%	100%	100%	100%	100%	100%	100%
2,501 - 5,000 ft	100%	86%	97%	92%	94%	95%	86%
5,001 - 7500 ft	83%	85%	96%	91%	91%	89%	84%
7,501 - 10,000 ft	67%	79%	69%	87%	76%	68%	80%
10,001 - 12,500 ft	50%	61%	36%	61%	48%	42%	65%
12,501 - 15,000 ft	50%	47%	28%	36%	23%	42%	59%
15,001 - 17,500 ft	0%	29%	12%	13%	8%	37%	47%
>17,500 ft	0%	26%	4%	7%	3%	32%	32%

Table 2-17. Regional rig-depth rating for natural gas

	East	Gulf Coast	Midcontinent	Southeast	Rocky Mountain	West Coast	Northern Great Plains
0 - 2,500 ft	100%	100%	100%	100%	100%	100%	100%
2,501 - 5,000 ft	95%	91%	97%	94%	93%	86%	100%
5,001 - 7500 ft	88%	90%	96%	94%	93%	86%	100%
7,501 - 10,000 ft	71%	86%	95%	91%	86%	57%	100%
10,001 - 12,500 ft	40%	74%	76%	65%	56%	29%	100%
12,501 - 15,000 ft	31%	68%	68%	47%	43%	0%	100%
15,001 - 17,500 ft	14%	52%	54%	21%	26%	0%	100%
>17,500 ft	10%	46%	47%	19%	21%	0%	100%

Regional rig equations

This section describes the regional rig equations used for the drilling determination for unconventional gas projects, including shale gas, coalbed methane, and tight gas.

The rig equations were developed using oil prices and state-level average monthly rig counts. The rig data were collected from Baker Hughes and aggregated to the OLOGSS regions. A one-year lag between prices and rig count was assumed. The form of the equation is:

$$\text{Rigs} = \beta 0 + \beta 1 * \ln(\text{Oil Price}) \tag{2.B-36}$$

where

$\beta 0$ = Intercept
$\beta 1$ = X Variable 1

The method of estimation used was ordinary least squares.

East Region Rig Equation

Regression Statistics	
Multiple R	0.9117
R Square	0.8312
Adjusted R Square	0.8294
Standard Error	7.7909
Observations	96.0000

ANOVA

	df	SS	MS	F	Significance F
Regression	1.0000	28100.298	28100.298	462.946	0.000
Residual	94.0000	5705.691	60.699		
Total	95.0000	33805.990			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-93.3466	7.226	-12.919	0.000	-107.693	-79.000	-107.693	-79.000
X Variable 1	41.8465	1.945	21.516	0.000	37.985	45.708	37.985	45.708

Gulf Coast Region Rig Equation

Regression Statistics	
Multiple R	0.9228
R Square	0.8515
Adjusted R Square	0.8499
Standard Error	28.7666
Observations	96.0000

ANOVA

	df	SS	MS	F	Significance F
Regression	1.0000	446093.817	446093.817	539.076	0.000
Residual	94.0000	77786.423	827.515		
Total	95.0000	523880.240			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-260.3122	26.679	-9.757	0.000	-313.284	-207.340	-313.284	-207.340
X Variable 1	166.7310	7.181	23.218	0.000	152.473	180.989	152.473	180.989

Midcontinent Region Rig Equation

Regression Statistics	
Multiple R	0.9035
R Square	0.8163
Adjusted R Square	0.8143
Standard Error	32.4800
Observations	96.0000

ANOVA

	df	SS	MS	F	Significance F
Regression	1.0000	440541.240	440541.240	417.594	0.000
Residual	94.0000	99165.499	1054.952		
Total	95.0000	539706.740			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-381.8852	30.123	-12.677	0.000	-441.696	-322.075	-441.696	-322.075
X Variable 1	165.6901	8.108	20.435	0.000	149.591	181.789	149.591	181.789

Southwest Region Rig Equation

Regression Statistics	
Multiple R	0.9495
R Square	0.9015
Adjusted R Square	0.9005
Standard Error	39.8516
Observations	96.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.0000	1366991.026	1366991.026	860.744	0.000
Residual	94.0000	149286.075	1588.150		
Total	95.0000	1516277.102			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-761.8706	36.960	-20.613	0.000	-835.255	-688.486	-835.255	-688.486
X Variable 1	291.8677	9.948	29.338	0.000	272.115	311.620	272.115	311.620

Rocky Mountain Region Rig Equation

Regression Statistics	
Multiple R	0.9185
R Square	0.8436
Adjusted R Square	0.8420
Standard Error	26.0566
Observations	96.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.0000	344290.807	344290.807	507.095	0.000
Residual	94.0000	63821.003	678.947		
Total	95.0000	408111.810			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-340.2829	24.166	-14.081	0.000	-388.265	-292.301	-388.265	-292.301
X Variable 1	146.4758	6.505	22.519	0.000	133.561	159.391	133.561	159.391

West Coast Region Rig Equation

Regression Statistics	
Multiple R	0.8970
R Square	0.8046
Adjusted R Square	0.8018
Standard Error	3.9768
Observations	72.0000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.0000	4558.709	4558.709	288.247	0.000
Residual	70.0000	1107.069	15.815		
Total	71.0000	5665.778			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-48.6162	4.540	-10.708	0.000	-57.671	-39.561	-57.671	-39.561
X Variable 1	20.1000	1.184	16.978	0.000	17.739	22.461	17.739	22.461

Northern Great Plains Region Rig Equation

Regression Statistics								
Multiple R	0.9154							
R Square	0.8380							
Adjusted R Square	0.8362							
Standard Error	8.1118							
Observations	96.0000							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1.0000	31986.497	31986.497	486.106	0.000			
Residual	94.0000	6185.336	65.801					
Total	95.0000	38171.833						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-121.5713	7.523	-16.159	0.000	-136.509	-106.634	-136.509	-106.634
X Variable 1	44.6464	2.025	22.048	0.000	40.626	48.667	40.626	48.667

Regional dryhole rates

The OLOGSS model uses three dryhole rates in the economic and footage calculations. These rates are for:

- Existing and discovered projects
- The first well drilled in an exploration oil or natural gas project
- The subsequent wells drilled in that project.

In this section, the development and values for each of these three rates will be described.

Discovered projects

The percentage allocation for existing regional dryhole rates was estimated using an updated EIA well-count file. The percentage is determined by the average footage drilled in 2010 for each corresponding region. Existing dryhole rates calculate the projects that have already been discovered. The formula for the percentage is given below:

Existing Dryhole Rate = Developed Dryhole / Total Drilling (2.B-37)

Table 2-18. Regional dryhole rates for existing fields and reservoirs

Region	States Included	Dry Hole Rate
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	2.8%
Gulf Coast	AL, FL, LA, MS, TX	7.0%
Midcontinent	AR, KS, MO, NE, OK, TX	7.8%
Southwest	TX, NM	5.5%
Rocky Mountain	CO, NV, UT, WY, NM	1.1%
West Coast	CA, WA	5.4%
Northern Great Plains	MT, ND, SD	1.8%

First exploration well drilled

The percentage 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 in 2010 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:

$$\text{Undiscovered Exploration} = \text{Exploration Dryhole} / (\text{Exploration Gas} + \text{Exploration Oil}) \tag{2.B-38}$$

Table 2-19. Regional dryhole rates for the first exploration wells

Region	States Included	Dry Hole Rate
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	7.7%
Gulf Coast	AL, FL, LA, MS, TX	176.6%
Midcontinent	AR, KS, MO, NE, OK, TX	79.6%
Southwest	TX, NM	53.0%
Rocky Mountain	CO, NV, UT, WY, NM	41.5%
West Coast	CA, WA	36.7%
Northern Great Plains	MT, ND, SD	6.0%

Regional dryhole rate for subsequent exploration wells drilled

The percentage 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 in 2010 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:

$$\text{Undiscovered Developed} = (\text{Developed Dryhole} + \text{Explored Dryhole}) / \text{Total Drilling} \tag{2.B-39}$$

2-20. Regional dryhole rates for subsequent exploration wells

Region	States Included	Dry Hole Rate
East	IN, IL, KY, MI, NY, OH, PA, TN, VA, WV	5.0%
Gulf Coast	AL, FL, LA, MS, TX	9.5%
Midcontinent	AR, KS, MO, NE, OK, TX	12.9%
Southwest	TX, NM	6.3%
Rocky Mountain	CO, NV, UT, WY, NM	1.8%
West Coast	CA, WA	6.9%
Northern Great Plains	MT, ND, SD	2.8%

Appendix 2.C. Decline Curve Analysis

This material has been moved to the Decline Curve Analysis section of the *Annual Energy Outlook*.

Appendix 2.D. Representation of Power Plant and xTL Captured CO_2 in Enhanced Oil Recovery

With the addition of the Capture, Transport, Utilization, and Storage (CTUS) Submodule and the revised representation of CO_2 enhanced oil recovery (EOR), the Electricity Market Module (EMM), Oil and Gas Supply Module (OGSM), and Liquid Fuels Market Module (LFMM) were modified so that these models all share a common vision of the market for CO_2. The current representation of CO_2 EOR better integrates the EMM, OGSM, LFMM, and CTUS.

- When considering CO_2 EOR, the OGSM competes natural and industrial options for CO_2 supply in each region against the availability and price of CO_2 from power plants and xTL facilities.[3] The OGSM passes its resolution of the CO_2 market to the EMM and LFMM.
- The EMM considers as a part of its overall objective function retrofitting existing units or building new generating units with CO_2 capture to meet a new constraint of satisfying the total CO_2 demand passed from OGSM. Because the EMM has the total picture as represented in the OGSM, it can determine the CO_2 market size and competitive prices for CO_2 captured from power generators (including transport and storage costs provided by the CTUS). The EMM then passes its resolution of the CO_2 market to the OGSM and LFMM.
- In a parallel fashion to the EMM, the LFMM considers as a part of its overall objective function building (but not retrofitting) xTL facilities to meet a new constraint of satisfying the total CO_2 demand passed from the OGSM and EMM. Because the LFMM has the total picture as represented in the OGSM, it can determine the CO_2 market size and competitive prices for CO_2 captured from xTL facilities (including transport and storage costs provided by the CTUS). The LFMM then passes its resolution of the CO_2 market to the OGSM and LFMM.

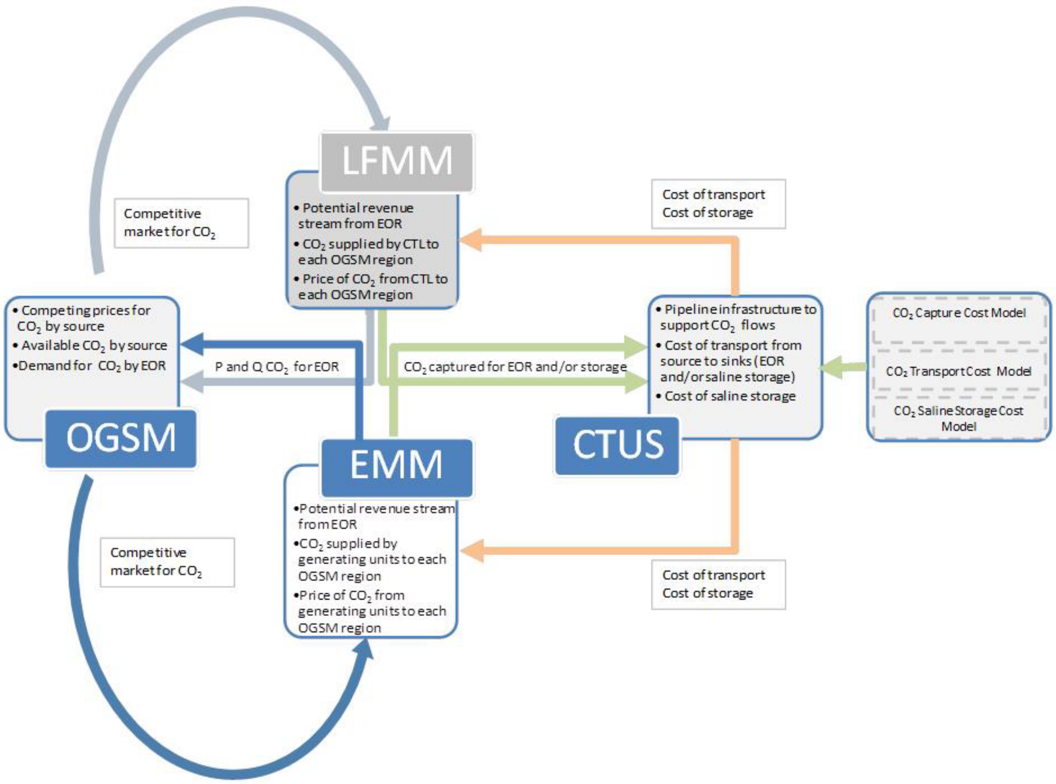
This structure enables the model to dynamically solve for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

The OGSM generates the CO_2 demand for EOR, which it then shares with the EMM and LFMM. The EMM Electricity Capacity Planning Module (ECP) and LFMM share the marginal cost (price) of CO_2 supply with OGSM for use in its selection of CO_2 sources among competitive suppliers. Quantities of CO_2 captured from the EMM and LFMM are also sent to CTUS for use in EOR and also for storage. The CTUS calculates and shares the cost of CO_2 transportation and storage with both the EMM and LFMM. Figure 2.D-1 illustrates the flow of information among these modules.

To facilitate the flow of information between the CTUS, EMM, OGSM, and LFMM, several new variables were introduced and are summarized in Table 2.D-1.

[3] Generic designation for process converting anything to liquids, such as for gas-to-liquid (GTL), coal-to-liquid (CTL), and biomass-to-liquid (BTL).

Figure 2.D-1. Flow of information among EMM, LFMM, OGSM, and CTUS



EMM data shared	CTUS data shared	OGSM data shared	LFMM data shared
CO_2 supply (to OGSM)	Cost of CO_2 transport and storage for power plants (to EMM)	Competitive Market for CO_2/CO_2 demand (to EMM)	CO_2 supply (to OGSM)
CO2 price (to OGSM)	Cost of CO_2 transport and storage for CTLs (to LFMM)	Competitive Market for CO_2/CO_2 demand (to LFMM)	CO_2 price (to OGSM)
CO_2 capture for EOR and storage (to CTUS)			CO_2 capture for EOR and storage (to CTUS)

Table 2.D- 1. Inventory of Variables Passed Between CTUS, OGSM, EMM and LFMM

Variable Name	Variable Type	Description	Units
OGCO2PUR2(8,13,MNUMYR)*	Variable	Volume of CO2 purchased. Same as OGCO2PUR but organized by CO_2 destination region.	MMcf
OGCO2PEM(8,MNUMYR)	Variable	CO_2 price from EMM - 2nd year dual including transport costs. These OGCO2PEM prices get loaded into OGCO2PRC for power plants.	$/MMcf
OGCO2PLF(8,MNUMYR)	Variable	CO_2 price from LFMM. These OGCO2PLF prices get loaded into OGCO2PRC for xTL plants.	$/MMcf
OGCO2PRC(8,13,MNUMYR)	Variable	CO_2 price by source. Note: Transport costs are not included for industrial sources; transport *is* included for power plants and xTL plants.	$/MMcf
OGCO2QEM(8,MNUMYR)	Variable	CO_2 quantity from EMM to OGSM. Note: 8th slot is *not* the same definition—it is the extra CO_2 that is not sent to EOR but sent to saline storage, instead (national basis).	MMcf
OGCO2QLF(8,MNUMYR)	Variable	CO_2 quantity from LFMM. Note: 8th slot is *not* the same definition—it is the extra CO_2 that is not sent to EOR but sent to saline storage, instead (national basis).	MMcf
OGCO2TAR(8,8)	Variable	Transport price from OGSM for industrial sources.	$/MMcf

*Note: For each of the variables, *8* refers to each of the seven OGSM regions plus national; *13* refers to each of the CO2 source technology options and MNUMYR refers to the year in which the activity takes place.

Integration of EMM into CO_2 EOR process

The EMM represents power plants with CO_2 capture. These facilities capture CO_2 and send it to either EOR or saline storage. With the addition of the CTUS model, the EMM was modified so that the NEMS OGSM model, the NEMS LFMM model, and the EMM all share a common vision of the market for CO_2 capture, transportation, and storage. To that end, the EMM is given the following:

- The EOR demand for CO_2 by NEMS OGSM region
- The prices for purchased CO_2 from sources other than power plants (such as xTL facilities)
- The cost of transporting CO_2 from EMM fuel regions to OGSM regions (from CTUS)
- The cost of transporting CO_2 between OGSM regions

The EMM returns the following:

- The amount of captured CO_2 from power plants used to satisfy EOR demand in each OGSM region
- The additional amount of captured CO_2 from power plants that is available to satisfy EOR demands (in Carbon Constrained scenarios EMM may capture CO_2 and send it to saline storage)
- The marginal price of CO_2 from power plants

Mathematical description of EMM-CTUS constraints

The mathematical representation of the CO_2 capture constraints in EMM are described below.

Definition of sets and parameters:

O ≡ Set of NEMS OGSM regions
F ≡ Set of NEMS EMM fuel regions
S ≡ Set of CO_2 sources
D_O ≡ Demand for CO_2 from EOR sites in OGSM region *(O)*
$P_{O,S}$ ≡ CO_2 production cost in OGSM region *(O)* from CO_2 source *(S)*
$T_{O,O'}$ ≡ CO_2 transportation cost from OGSM region *(O)* to OGSM region *(O')*
$T_{F,O}$ ≡ CO_2 transportation cost from fuel region *(F)* to OGSM region *(O)* for use in EOR
$TS_{F,O}$ ≡ CO_2 transportation and storage cost from fuel region *(F)* to OGSM region *(O)* for injection into a saline storage site
$A_{O,S}$ ≡ Quantity of available CO_2 for OGSM region *(O)* from CO_2 source *(S)*
$CO2\_CAP$ ≡ Quantity of CO_2 captured per unit of electricity produced

Definition of decision variables:

EMM_OP_F = Operation level of power plants fuel region *(F)*
$EMM\_EOR_{F,O}$ = Amount of CO_2 captured from the operation of power plants in fuel region *(F)* and transported to OGSM region *(O)* for use in EOR
EMM_SAL_F = Amount of CO_2 captured from the operation of power plants in fuel region *(F)* and transported for injection into saline sites
$CO2\_TRAN_{O,O'}$ = Amount of CO_2 transported from OGSM region *(O)* to OGSM region *(O')* for use in EOR from non-power plant sources
$CO2\_PURCH_{O,S}$ = Amount of CO_2 purchased in OGSM region *(O)* from CO_2 source *(S)*

Definition of the constraints:

- OGSM EOR demand for CO_2 must be satisfied in each OGSM region *(O)*:
  The amount of CO_2 transported into OGSM region (O) from all other OGSM regions plus the amount of CO_2 transported into this OGSM region from power plants plus the amount of CO_2 purchased from xTL sources[4] in this OGSM region must equal the EOR CO_2 demand in this OGSM region.

$$\sum_{O} CO2\_TRAN_{O,O'} + \sum_{F} EMM\_EOR_{F,O} + CO2\_PURCH_{O,S(xTL)} - D_O = 0$$

- CO_2 that is purchased in each OGSM region (O) from sources other than from power plants or xTLs in each OGSM region (O) must be transported before it can be used to satisfy EOR demands.

[4] Note that the *CO2_PURCH* variable here is only for xTL sources because the purchase prices for CO_2 that come from the LFMM are *delivered costs*, so no transportation cost component needs to be added.

$$\sum_{S \neq power\ or\ XTL} CO2\_PURCH_{O,S} - \sum_{O'} CO2\_TRAN_{O,O'} = 0$$

- CO_2 that is captured from power plants in each fuel region (F) must be must either be sent to EOR or saline injection in carbon constrained scenarios.

$$CO2_{CAP} * EMM - \sum_{O} EMM\_EOR_{F,O} - EMM\_SAL_F = 0$$

Otherwise, the amount of CO_2 captured must exceed the amount shipped to EOR.

$$CO2_{CAP} * EMM - \sum_{O} EMM\_EOR_{F,O} - EMM\_SAL_F \geq 0$$

- The amount of CO2 that is purchased from source (S) in each OGSM region (O) is limited to the amount available.

$$CO2\_PURCH_{O,S} \leq A_{O,S}$$

Integration of LFMM into CO2 EOR process

The LFMM has process representations of coal-to-liquids and coal-plus-biomass-to-liquids facilities, which may capture CO_2 and send it to either EOR or saline storage. With the addition of the CTUS model, the LFMM was modified so that the NEMS OGSM model, the NEMS EMM model, and the LFMM all share a common vision of the market for CO_2 capture, transportation, and storage. To that end, the LFMM is given:

- The EOR demand for CO_2 by NEMS OGSM region
- The prices for purchased CO_2 from sources other than xTL (such as power plants)
- The cost of transporting CO_2 from EMM fuel regions to OGSM regions
- The cost of transporting CO_2 between OGSM regions

The LFMM returns:

- The amount of CO_2 from xTL sources used to satisfy EOR demand in each OGSM region
- The potential amount of CO_2 from xTL sources available to satisfy EOR demands
- The marginal price of CO_2 captured from xTL sources

Mathematical description of LFMM-CTUS constraints

The mathematical representation of the CO_2 capture constraints in LFMM are described below.

Definition of sets and parameters:

- $O \equiv$ Set of NEMS OGSM regions
- $F \equiv$ Set of NEMS EMM fuel regions
- $S \equiv$ Set of CO_2 sources
- $D_O \equiv$ Demand for CO_2 from EOR sites in OGSM region *(O)*

- $P_{O,S}$ ≡ CO_2 production cost in OGSM region *(O)* from CO2 source *(S)*
- $T_{O,O'}$ ≡ CO_2 transportation cost from OGSM region *(O)* to OGSM region *(O')*
- $T_{F,O}$ ≡ CO_2 transportation cost from fuel region *(F)* to OGSM region *(O)* for use in EOR
- $TS_{F,O}$ ≡ CO_2 transportation and storage cost from fuel region *(F)* to OGSM region *(O)* for injection into a saline storage site
- $A_{O,S}$ ≡ Quantity of available CO_2 for OGSM region *(O)* from CO_2 source *(S)*
- $CO2\_CAP$ ≡ Quantity of CO_2 captured per barrel of throughput of an xTL plant

Definition of the decision variables:

- XTL_OP_F = Operation level of xTL plants in fuel region *(F)*
- $XTL\_EOR_{F,O}$ = Amount of CO_2 captured from the operation of xTL plants in fuel region *(F)* and transported to OGSM region *(O)* for use in EOR
- XTL_SAL_F = Amount of CO_2 captured from the operation of xTL plants in fuel region *(F)* and transported for injection into saline sites
- $CO2\_TRAN_{O,O'}$ = Amount of CO_2 transported from OGSM region *(O)* to OGSM region *(O')* for use in EOR from non-xTL sources
- $CO2\_PURCH_{O,S}$ = Amount of CO_2 purchased in OGSM region *(O)* from CO2 source *(S)*

Definition of the constraints:

- Must satisfy OGSM EOR demand for CO_2 in each OGSM region *(O)*:
  The amount of CO_2 transported into OGSM region (O) from all other OGSM regions plus the amount of CO_2 transported into this OGSM region from xTL sources plus the amount of CO_2 purchased from power plants[5] in this OGSM region must equal the EOR CO_2 demand in this OGSM region.

$$\sum_{O} CO2\_TRAN_{O,O'} + \sum_{F} XTL\_EOR_{F,O} + CO2\_PURCH_{O,S(Power)} - D_O = 0$$

- CO_2 that is purchased in each OGSM region (O) from sources other than from xTLs or power plants in each OGSM region (O) must be transported before it can be used to satisfy EOR demands.

$$\sum_{S \neq power\ or\ XTL} CO2\_PURCH_{O,S} - \sum_{O'} CO2\_TRAN_{O,O'} = 0$$

- CO_2 that is captured from xTL sources in each fuel region (F) must be must either be sent to EOR or saline injection.

$$CO2_{CAP} * XTL_{OP_F} - \sum_{O} XTL_{EOR_{F,O}} - XTL_{SAL_F} = 0$$

- The amount of CO_2 that is purchased from source (S) in each OGSM region (O) is limited to the amount available.

[5] Note that the CO2_PURCH variable is only for power plant sources because the purchase prices for CO_2 that come from the EMM are *delivered costs*, so no transportation cost component needs to be added.

$$CO2\_PURCH_{O,S} \leq A_{O,S}$$

Implementation of 45Q legislation

The Section 45Q sequestration tax credit was amended and expanded in the Furthering Carbon Capture, Utilization, Technology, Underground Storage, and Reduced Emissions Act or FUTURE Act passed as part of the Bipartisan Budget Act of 2018.[6] The purpose of the legislation is to provide a financial incentive to industrial entities to capture and sequester CO_2 that would otherwise be vented to the atmosphere. The 45Q credits provide additional value for carbon capture utilization and storage (CCUS) technologies for the first 12 years of operation for plants that start construction before January 1, 2024. These credits are available to both power and industrial sources that capture and permanently sequester CO_2 in geologic storage and for use in enhanced oil recovery (EOR). Credit values are defined as follows:

- The tax credit for CO_2 used for EOR ramps in starting at $12.83 per metric ton in 2017 and rises linearly to $35 per metric ton by 2026. After 2026, credits rise with inflation.
- The tax credit for CO_2 that is permanently stored in saline aquifers ramps up starting at $22.66 per metric ton in 2017 and rises linearly to $50 per ton by 2026. After 2026, credits rise with inflation.

For purposes of the model, the 45Q credits are available to new and retrofit CCUS generators until January 1, 2024, plus an assumed average construction time for CCUS technologies in both the power and industrial sectors. The credit values are adjusted (endogenously) to be revenue equivalences by the average corporate tax rate in each year. Credits are expressed in nominal dollars until after 2026 when the credits rise with inflation as specified in the legislation. Annual payments to generators are based on the credit value in each operating year, so all generators benefit from the rising credit value over time regardless of online year. Payments are made for the first 12 years of operations.

Modifications to the EMM

Changes were made to the Electricity Market Module (EMM) to reduce the CO_2 transport cost for new and retrofit CCUS plant investment and operating decisions to reflect the value of the credits. A new capability was added to allow power plants to make an economic decision to reduce or stop operating their CO_2 capture equipment once the 45Q credit payments expire.

Electricity Capacity Planning (ECP) changes

In the ECP LP, the operate vectors for plant types that incorporate carbon capture technology intersect a balance constraint to collect all the captured CO_2. A balance row exists for each fuel region in each of the planning periods. The other vectors that intersect these balance rows are CO_2 transport vectors that allow the LP the option to either ship the captured CO_2 to EOR projects in one of seven OGSM regions or to be sequestered in saline aquifers. In the absence of a carbon policy, the CO_2 can be vented. Because the captured CO_2 must either be sequestered or sent to EOR projects to receive the 45Q tax credit, the balance row is set to an equality row. Any CO_2 captured must activate one or more of the transport

[6] For more information about the FUTURE Act, visit https://www.congress.gov/bill/115th-congress/senate-bill/1535/all-info

vectors. Normally, the objective value of these transport vectors is the cost to either transport the CO_2 to EOR projects (net of CO_2 revenues from EOR production) or the cost to transport and sequester the CO_2 at the closest and least expensive geological formation where sequestering is possible. The objective function values of these transport vectors are reduced by the value of the 45Q tax credit, which will incentivize investment in carbon capture technology.

However, in the ECP the operate vectors are for all units of the same plant type, no matter what the vintage. For new units built each year, the tax credit is good for the entire duration allowed but, for other older units of the same type, the remaining years of eligibility are lower. To model the legislation as written would require a new set of operate vectors for each vintage. This new set of operate vectors would require a large expansion of the ECP matrix, and most likely the matrix would no longer fit in the limited solution space. We decided to focus on ensuring that the new investments receive the full credit value and can make an accurate investment decision. This focus means that during the period that new investment can qualify for the tax credit, older vintages are receiving credits that they may not be supposed to receive. In the later forecast years when new capture investments can no longer qualify for the 45Q tax credit, the older plants will also not receive any remaining tax credit payments that they should be receiving if they are still in their eligibility period, which could affect the model's operation of these plants.

Another objective was to revise the EMM code to allow units with CO2 capture technology to operate at a lower capture rate if it is economical to do so. This option is necessary because 45Q provides a subsidy for captured CO_2, but there is a limited window of time in which a unit can receive this subsidy. So, the subsidy may stimulate investment in new plants with capture or existing units that retrofit with carbon capture, but when these units no longer receive a subsidy, it is possible that the most economical choice for these units is to reduce the use of the carbon capture equipment. This action can significantly increase a plant's ability to sell electricity to the grid and result in greater revenues with the same costs. Whether these units will be allowed to suspend carbon capture is unknown, so the model user has the option of using data inputs to specify if plants are allowed to stop capturing in full or in part. The partial carbon capture option is provided to accommodate the possibility that new CCUS plants would be in violation of the Clean Air Act 111b rules if they were to stop capturing but would follow a lower capture rate.

The ECP passes to CTUS the average capacity factor (CF_NAT) for CCUS plants by technology type, which the CTUS model uses to develop its view of CO_2 captured. The capacity factor is computed to reflect only the captured portion of the generation.

Electricity Fuel Dispatch (EFD) changes

For units with capture, the EFD code distinguishes between those units that still receive the 45Q credits and those that no longer qualify for the credits. The units that still receive the 45Q credits send their captured carbon to a subsidized carbon balance row, and the rest of the units send their captured carbon to a carbon balance row, where the full transport and storage costs must be paid.

In addition, the EFD code was modified to allow units with carbon capture to operate with or without capture based on data inputs that specify the degree to which these units can restrict the use of the capture equipment. The capture rate is input from the ECPDATY.xlsx input file for each CCUS technology and stored in the UPPCEF(ECPt) array. A parallel vector, UPPCEF_MIN(ECPt), was created that specifies the minimum capture allowed for each technology. For any given plant type, if the two values match, then there is no option to change the capture rate. If the minimum rate is less than the full rate, then the set of alternative operate vectors at lower capture rates is created.

A second set of inputs in the EMMCNTL.txt file specifies the capacity and heat rate penalties associated with reduced capture operations. The capacity penalty and the heat-rate penalty are always the inverse of each other. For CCUS plants, the unit consumes the same amount of fuel with or without capture, but parasitic energy needed for capture reduces the amount of capacity that can be committed to meet load (capacity penalty). To compensate, the heat-rate must increase so that fuel consumption remains constant (heat-rate penalty). The relationship is defined by the following equality: Orig CAP * Orig HTRT = ADJ_CAP * ADJ_HTRT.

Currently, an input in the EMMCNTL.txt file specifies the *average capacity penalty factor* by ECP type, UECP_CPEN_ADJ(ECPt).[7] For example, existing coal plants have a *capacity penalty factor* of 0.730 and a *capacity penalty* of 0.270, and so a 100-megawatt (MW) plant will produce 73 MW for the grid after installing CCS. The capacity penalty factor is also the inverse of the heat rate adjustment factor UECP_HTRT_ADJ. A new parallel array, ALT_UECP_CPEN_ADJ(ECPt), was created that defines the capacity penalty factor with minimum capture and makes it possible to assess the economic impact of reducing a plant's capture rate.

All natural gas CCS plants (new or retrofits) are assumed to be able to stop capturing completely, although coal CCS plants (new or retrofits) are assumed to require a minimum of 30% carbon capture, to comply with the Clean Air Act 111b rules.

A new variable, ADJ_FAC, represents the amount of capacity that can be regained by reducing the capture percentage. If this factor is greater than 1.0, the alternative operate vectors are created. The calculation of the ADJ_FAC also uses a relationship between the reduced capture rate and associated capacity/heat-rate penalty. ADJ_FAC equals ALT_UECP_CPEN_ADJ(ECPt) / (1.0 – UGNOCCS(N_EFD_GRPS)) where UGNOCCS(N_EFD_GRPS)) is the average capacity penalty for the dispatch group. It is defined by averaging the unit-level capacity penalty (ECNOCCS(ECNTP)) over all the units in the group. For units to belong in the same group, they must be nearly alike, that is, same regions, same plant types, similar heat rates, and now must have the same 45Q start date. In turn, ECNOCCS(ECNTP) is defined by the CCSCAPA variable that is stored on the individual plant records (CCSCAPA = 1.0 – the capacity penalty factor). For new CCS plants, UGNOCCS is the same as the capacity

[7] Capacity Penalty Factor = (1.0 – Capacity Penalty) so Capacity Penalty = (1.0 – Capacity Penalty Factor). The unit-specific capacity penalties are specified in the input plant file for plants that could undertake CCS retrofits. The average rates in the EMMCNTL.txt file are used in places where the ECP needs average rates by plant type and were previously only used for existing plants.

penalty (1 – UECP_CPEN_ADJ) where UECP_CPEN_ADJ is defined in EMMCNTL.txt. The capacity penalty factor, UECP_CPEN_ADJ, is equivalent to the ratio of the *No CCS* technology heat rate and the CCS technology heat rate. The corresponding *No CCS* technology's ECP type is also defined in EMMCNTL.txt as the new variable NO_CCS_PLNTCD. This definition assumes that plants with carbon capture that stop capturing become equivalent to plants that were built without capture from the start.

For example, for a new natural gas CCS unit that can stop capturing entirely:

ALT_UECP_CPEN_ADJ(ECPt) = 1.0, in other words the capacity after stopping capture = capacity without capture because the minimum capture rate is 0%.

UECP_CPEN_ADJ(ECPt) = 0.827, derived by capacity penalty factor = "AC" heat rate (with no capture) / "CS" heat rate (with full capture) in 2025 = 6200 / 7493 = 0.827,

UGNOCCS(group) = capacity penalty factor = (1.0 – 0.827) or 0.173,

ADJ_FAC = (ALT_UECP_CPEN_ADJ(ECPt) / (1.0 - UGNOCCS(group)) = (1.0 / (1.0 – 0.173) = 1.209

For a new coal CCS unit that can reduce to 30% capture, the partial (30%) capture heat rate penalty was used to derive the associated capacity penalty factor:

ALT_UECP_CPEN_ADJ(ECPt) = 0.996, which was defined as the "PQ" heat rate (with 30% capture) / "IS" heat rate (with full capture) = 9221/9257 = 0.996

UECP_CPEN_ADJ(ECPt) = 0.805, derived by capacity penalty = "IG" heat rate (with no capture) / "IS" heat rate (with full capture) in 2025 = 7450 / 9257 = 0.805,

UGNOCCS(group) = capacity penalty factor = (1.0 – 0.805) or 0.195,

ADJ_FAC = 0.996 / (1.0 – 0.195) = 1.238

The final step is to ensure the fuel used at the minimum capture level reflects the correct mix of CO_2 emitted and CO_2 captured. The final step is important because the cost of the British thermal units used also includes the cost of CO_2 emitted. For unconstrained carbon cases, this cost is zero, but for carbon-constrained cases, the CO_2 cost is typically greater than zero. To accomplish this result, each plant type with CO_2 capture is paired to a similar plant type without capture. The fuel used by this pair of plant types is mixed so that the CO_2 emissions are consistent with the emissions from the plants with capture operating at the minimum capture rate. The share of fuel without capture is:

SHR_NOCCS = (CO2_CCS_MIN – CO2_CCS) / (CO2_NOCCS – CO2_CCS)

SHR_CCS = 1.0 – SHR_NOCCS

Where: CO2_CCS = 1.0 – UPPCEF(capture)

CO2_CCS_MIN = 1.0 – UPPCEF_MIN(capture)

CO2_NOCCS = 1.0 – UPPCEF(no_capture)

For the coal unit example above: CO2_CCS = 1.0 – 0.9 = 0.1

CO2_CCS_MIN = 1.0 – 0.3 = 0.7

CO2_NOCCS = 1.0 – 0.0 = 1.0

SHR_NOCCS = (0.7 – 0.1) / (1.0 – 0.1) = 0.6 / 0.9 = 0.6667

SHR_CCS = 1.0 – 0.6667 = 0.3333

Modifications to the OGSM

OGSM was modified with new arrays and bin sorting routines to reflect the 45Q credits for industrial CO_2 capture and to track the CCUS plants built or retrofit that are eligible to receive the credits. The original OGSM computed the potential industrial CO_2 available for EOR once in the first model year using supply curves and industry-specific ramp rates. In the new structure, the arrays must be sorted each year to account for 45Q credits, and a new array, NS_PRC_NDX, maps the sorted project list in each year to the original project indexes. NS_Price dimensions were expanded to include a year dimension to use for the 45Q subsidy values, and the bin breakpoints are reset to accommodate the annual subsidies. A new array, NS_START, records the year each project is selected for storage and compression of CO_2. It is collected from a previous cycle/run and stored in the restart file. This array is used to determine if the project receives a subsidy in each forecast year (whether it has been selected in a previous year and is still within its eligibility period), based on OGSM's decision to use CO_2 from this project.

All the captured CO_2 from industrial sources is sent to EOR projects. There is no ability for industrial captured CO_2 to be sent to saline storage.

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 three categories:

1. **Undiscovered fields**. The number, location, and size of the undiscovered fields are based on the Minerals Management Service's (MMS) 2006 hydrocarbon resource assessment. MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in 2010 and then replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) in 2011 as part of a major reorganization.
2. **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.
3. **Producing fields**. The fields in this category have wells that have produced oil and/or natural gas by 2010. The production volumes are from the BOEM production 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, 800–1,600 meters, 1,600–2,400 meters, and greater than 2,400 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 responds 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 natural gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico (GOM). Exploration and development of these resources is projected in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on BOEM's 2016[8] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by BOEM 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

[8] U.S. Department of Interior, Bureau of Ocean Energy Management, Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2016.

assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomical to develop.

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 – 1,600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1,601 – 2,400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2,400	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

Table 3-1. Offshore region and evaluation unit crosswalk (cont.)

No.	Region name	Planning area	Water depth (meters)	Drilling depth (feet)	Evaluation unit name	Region ID
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	801-1,600	All	NCA0816	2
39	Pacific	North California	1,600-2,400	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	801-1,600	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	801-1,600	All	SCA0816	2
46	Pacific	South California	1,601-2,400	All	SCA1624	2

Data source: U.S. Energy Information Administration, Office of Energy Analysis, Office of Petroleum, Natural Gas, and Biofuels Analysis

Table 3-2. Number of undiscovered fields by evaluation unit and field size class, as of January 1, 2014

Evaluation Unit	Field Size Class 2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	Number of Fields	Total Resource (BBOE)
WGOM0002	12	20	28	39	38	39	34	25	13	9	3	3	2	1	0	0	266	3,605
WGOMDG02	6	10	14	19	19	19	17	13	7	4	2	2	1	0	0	0	133	1,582
WGOM0204	0	0	1	1	1	2	3	4	4	4	2	1	0	0	0	0	23	698
WGOM0408	1	0	1	1	2	3	5	6	7	5	4	2	1	0	0	0	38	1,564
WGOM0816	1	1	2	6	10	16	25	29	30	23	15	8	3	1	0	0	170	6,783
WGOM1624	0	1	1	2	3	6	8	9	11	8	5	4	2	0	0	0	60	2,651
WGOM2400	0	0	1	2	3	4	5	5	6	5	3	3	1	0	0	0	38	1,620
CGOM0002	17	30	43	59	59	58	55	46	21	13	7	5	3	1	0	0	417	5,511
CGOMDG02	8	15	21	29	30	29	28	23	11	6	3	3	1	0	0	0	207	2,265
CGOM0204	0	0	1	2	4	5	9	12	12	10	6	2	1	0	0	0	64	2,184
CGOM0408	0	1	2	3	5	8	14	19	19	14	8	3	1	1	0	0	98	3,693
CGOM0816	1	3	4	9	17	26	47	63	63	48	32	15	5	2	0	0	335	13,388
CGOM1624	1	2	4	8	14	24	39	50	54	42	30	15	7	2	0	0	292	13,241
CGOM2400	0	2	1	4	7	14	23	29	31	26	19	11	5	2	0	0	174	9,211
EGOM0002	5	7	7	8	9	9	7	6	5	2	2	2	0	0	0	0	69	896
EGOM0204	2	2	2	3	3	3	2	2	1	1	1	0	0	0	0	0	22	209
EGOM0408	2	2	4	4	4	5	3	2	1	1	1	0	0	0	0	0	29	224
EGOM0816	2	1	3	3	2	2	2	1	2	1	0	0	0	0	0	0	19	126
EGOM1624	0	1	1	1	1	0	0	0	0	1	0	0	0	0	0	0	5	47
EGOM2400	1	1	2	1	5	7	9	12	14	12	7	4	3	1	0	0	79	4,175
EGOML181	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NATL0002	0	1	1	0	2	3	3	5	7	3	1	1	0	0	0	0	27	648
NATL0208	0	1	0	1	2	2	2	4	4	3	2	0	0	0	0	0	21	474
NATL0800	0	1	0	1	1	3	3	5	6	5	4	3	2	1	0	0	35	2,742
MATL0002	1	0	1	1	2	3	3	2	2	3	2	0	0	0	0	0	20	413
MATL0208	1	1	0	0	2	3	3	4	3	3	2	1	1	0	0	0	24	991
MATL0800	1	0	0	0	2	5	6	8	10	11	9	7	5	1	0	0	65	5,385
SATL0002	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SATL0208	1	1	1	0	2	4	4	2	1	1	0	0	0	0	0	0	17	129
SATL0800	0	0	1	0	5	6	6	6	5	4	2	0	0	0	0	0	35	603
PNW0002	11	17	24	30	27	20	13	8	5	2	1	0	0	0	0	0	158	596
PNW0208	5	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	60	209
NCA0002	1	3	4	6	5	5	5	4	3	3	2	0	0	0	0	0	41	487
NCA0208	10	17	24	28	26	22	14	9	6	3	1	1	0	0	0	0	161	859
NCA0816	4	6	10	12	13	12	9	7	4	3	2	1	0	0	0	0	83	783
NCA1624	2	2	3	5	6	7	6	5	3	3	1	1	0	0	0	0	44	595

Table 3-2. Number of undiscovered fields by evaluation unit and field size class, as of January 1, 2014 (cont.)

	Field Size Class																	Total
Evaluation Unit	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**Number of Fields**	**Resource (BBOE)**
CCA0002	1	5	6	11	16	20	20	18	12	8	4	2	0	0	0	0	123	1,762
CCA0208	1	2	3	5	8	9	9	9	5	5	1	1	0	0	0	0	58	803
CCA0816	1	1	1	1	3	3	3	4	3	3	0	0	0	0	0	0	23	280
SCA0002	1	0	2	2	5	8	9	9	7	6	3	1	0	0	0	0	53	1,063
SCA0208	2	2	5	10	15	23	28	26	21	16	6	3	1	0	0	0	158	3,182
SCA0816	2	3	7	10	14	19	19	17	14	10	3	1	1	0	0	0	120	1,964
SCA1624	1	1	3	3	4	6	6	4	3	3	2	0	0	0	0	0	36	491

Data source: U.S. Energy Information Administration, Office of Energy Analysis, Office of Petroleum, Natural Gas, and Biofuels Analysis

Table 3-3. Field size definition

Field Size Class	Minimum	Mean	Maximum
2	0.0625	0.096	0.125
3	0.125	0.186	0.25
4	0.25	0.373	0.5
5	0.5	0.755	1
6	1	1.432	2
7	2	3.011	4
8	4	5.697	8
9	8	11.639	16
10	16	23.026	32
11	32	44.329	64
12	64	90.327	128
13	128	175.605	256
14	256	357.305	512
15	512	692.962	1,024
16	1,024	1,392.702	2,048
17	2,048	2,399.068	4,096

Data source: U.S. Energy Information Administration, Office of Energy Analysis, Office of Petroleum, Natural Gas, and Biofuels Analysis

Projection of discoveries

The number and size of discoveries is projected based on a simple model developed by J. J. Arps and T. G. Roberts in 1958.[9] For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by:

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \qquad (3\text{-}1)$$

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 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 of the search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to obtain enough data points to provide a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. The polynomial was fit to the resulting search coefficients as follows:

$$\gamma_{EU,iFSC} = (\beta 1 * iFSC^2 + \beta 2 * iFSC + \beta 3) * \gamma_{EU,10} \qquad (3\text{-}2)$$

where

β1	=	0.0243 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:

$$\text{CumNFW}_{\text{EU,t}} = \text{CumNFW}_{\text{EU,t-1}} + \alpha 1_{\text{EU}} + \beta_{\text{EU}} * (\text{OILPRICE}_{\text{t-nlag1}} * \text{GASPRICE}_{\text{t-nlag2}}) \qquad (3\text{-}3)$$

[9]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.

where

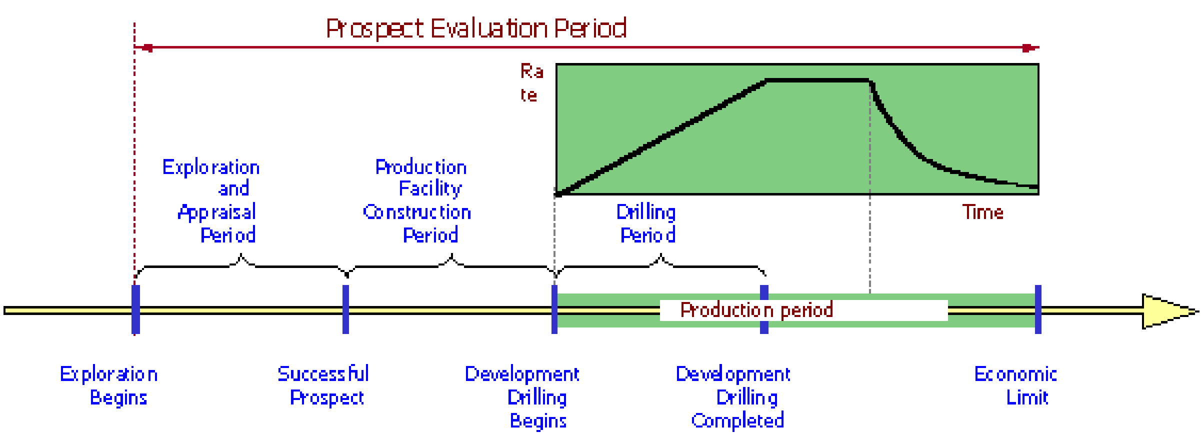
OILPRICE	=	oil wellhead price
GASPRICE	=	natural gas wellhead price
$\alpha1, \beta$	=	estimated parameter
nlag1	=	number of years lagged for oil price
nlag2	=	number of years lagged for natural gas price
t	=	year
EU	=	evaluation unit

The decision for exploration and development of the discoveries determined from Equation 3-1 is performed at a prospect level that could involve 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:

4. A single field with its own production facility
5. Multiple medium-size fields sharing a production facility
6. Multiple small fields utilizing a nearby production facility.

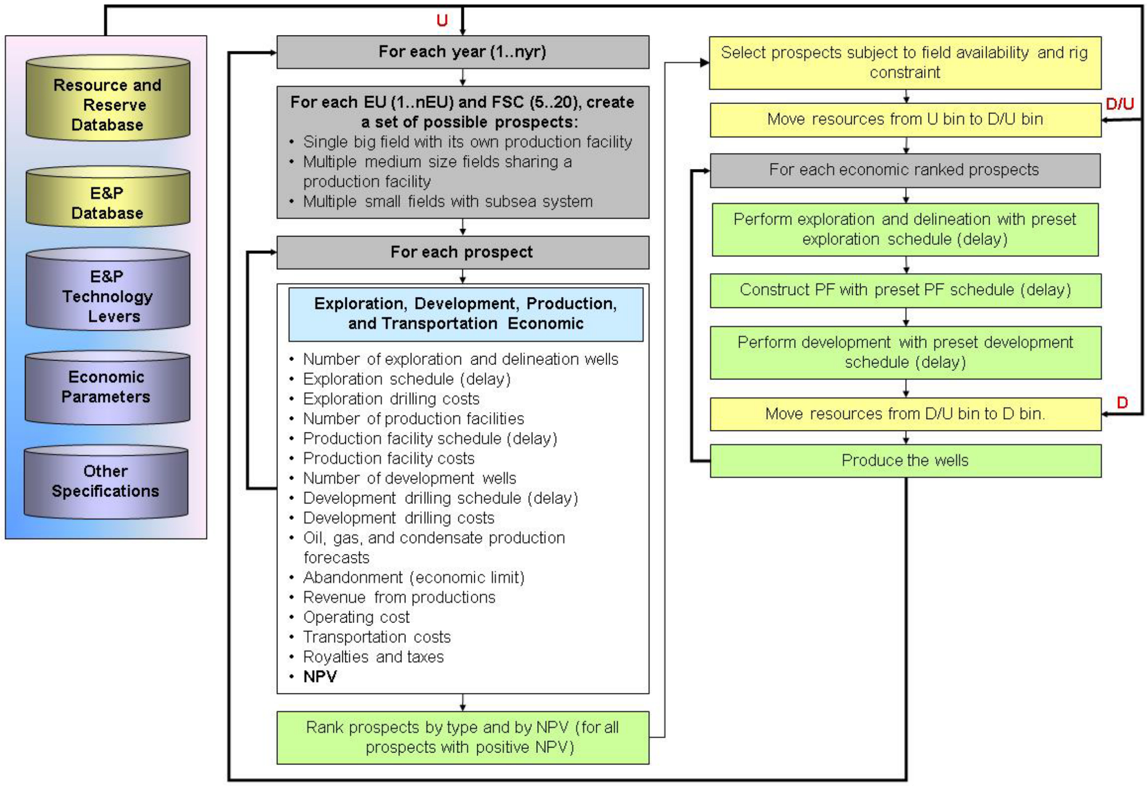
The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production 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 it represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater Outer Continental Shelf (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 [0.6 + (oilprice/baseprice)], where baseprice = $75/barrel.

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 process 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.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}000{,}000 + (5.0\text{E-}09)*\text{WD}*\text{DD}^3 \quad (3\text{-}4)$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This technique 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 semi-submersible rig tends to dampen wave motion greatly regardless of wave direction. This characteristic allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}500{,}000 + 400*\text{WD} + 200*(\text{WD}+\text{DD}) + (2.0\text{E-}05)*\text{WD}*\text{DD}^2 \quad (3\text{-}5)$$

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 cannot be deployed. Some of the drillships are designed with the rig equipment and anchoring systems mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This position helps to dampen wave motion.

$$\text{ExplorationDrillingCosts(\$/well)} = 7{,}500{,}000 + (1.0\text{E-}05)*\text{WD}*\text{DD}^2 \quad (3\text{-}6)$$

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 the Gulf of Mexico OCS. These are conventional fixed platforms, 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, although 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.

$$\text{StructureCost(\$)} = 2{,}000{,}000 + 9{,}000*\text{SLT} + 1{,}500*\text{WD}*\text{SLT} + 40*\text{WD}^2 \quad (3\text{-}7)$$

Compliant towers (CT). The compliant tower is a narrow, flexible tower type of platform that is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the tower and terminating on piles 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.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \quad (3\text{-}8)$$

Tension leg platform (TLP). The tension leg platform is a type of semi-submersible structure that is attached to the seabed 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 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 three years.

$$\text{StructureCost}(\$) = 2 * \{(\text{SLT} + 30) * \left(3{,}000{,}000 + 750 * (\text{WD} - 1{,}000)\right)\} \quad (3\text{-}9)$$

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%. These structures can only accommodate a maximum of about 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.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \quad (3\text{-}10)$$

Spar platform (SPAR). A 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 catenary 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 range to about 10,000 feet.

$$StructureCost(\$) = 100 * \{(SLT + 20) * \left(3{,}000{,}000 + 500 * (WD - 1{,}000)\right)\} \quad (3\text{-}11)$$

Subsea wells system (SS). Subsea systems range from a 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. Because 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.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \quad (3\text{-}12)$$

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

Minimum	Maximum	Fixed platform	Compliant tower	Tension leg platform	Floating production system	Single point anchor reservoir	Subsea system
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Data 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, are 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,

$$\text{DevelopmentDrillingCost}\left(\frac{\$}{\text{well}}\right) = 5 * \{1{,}500{,}000 + (1{,}500 + 0.04 * \text{DD}) * \text{WD}$$

$$+(0.035 * DD - 300) * DD\} \quad \text{(3-13)}$$

For water depths greater than 900 meters,

$$\text{DevelopmentDrillingCost}\left(\frac{\$}{\text{well}}\right) = 5 * \{4{,}500{,}000 + (150 + 0.004 * \text{DD}) * \text{WD}$$

$$+(0.035 * DD - 250) * DD\} \quad \text{(3-14)}$$

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

	Development Drilling Depth (feet)		
Water 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:

- Primary oil and natural gas production costs
- Labor
- Communications and safety equipment
- Supplies and catering services
- Routine process and structural maintenance
- Well service and workovers
- Insurance on facilities
- Transportation of personnel and supplies

Annual operating costs are estimated by

$$\text{OperatingCost}(\$/\text{structure}/\text{year}) = 3 * (1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2) \quad (3\text{-}15)$$

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 the 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 on the type of production technology used. The model projects abandonment costs for fixed platforms and compliant towers assuming that the structure is abandoned. It projects costs for tension leg platforms, converted semi-submersibles, and converted tankers assuming 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 on historical data, these costs are estimated as a fraction of the initial structure costs:

	Fraction of initial platform cost
Fixed Platform	0.10
Compliant Tower	0.10
Tension Leg Platform	0.10
Floating Production Systems	0.10
Spar Platform	0.10

Exploration, development, and production scheduling

The typical offshore project development consists of the following phases: [10]

- 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
- Field abandonment

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 that both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field.

Exploration phase

An undiscovered field is discovered by a successful exploration well (in other words, 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:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25% exploration success rate will require four exploratory wells: one of the four wildcat wells drilled finds the field and the other three are dryholes.

[10] 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.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (one to four 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 on 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.

$$\text{Development Wells} = \frac{3.8}{\text{FSC}} * \text{FSIZE}^{\beta\ \text{DepthClass}} \tag{3-16}$$

where

FSC = field size class

FSIZE = resource volume (million barrels of oil equivalent [MMBOE])

β = 0.75 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	4
FPS								3	3	3	4	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 one 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.

Table 3-7. Development drilling capacity by production facility type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)		Maximum Number of Wells Drilled (wells/field/year)			
Drilling Depth (feet)	**Drilling Capacity (24 slots)**	**Water Depth (feet)**	**SS**	**FPS**	**FPSO**
0	24	0	4		4
6,000	24	1,000	4		4
7,000	24	2,000	4		4
8,000	20	3,000	4	4	4
9,000	20	4,000	4	4	4
10,000	20	5,000	3	3	3
11,000	20	6,000	2	2	2
12,000	16	7,000	2	2	2
13,000	16	8,000	1	1	1
14,000	12	9,000	1	1	1
15,000	8	10,000	1	1	1
16,000	4				
17,000	2				
18,000	2				
19,000	2				
20,000	2				
30,000	2				

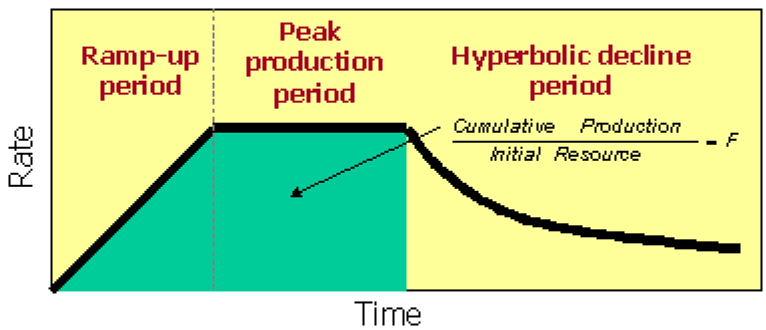
Data source: ICF Consulting

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user-specified proportion. Because of the development drilling schedule, not all wells in the same field will produce at the same time. This drilling schedule 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.

Natural gas (plus lease condensate) production is calculated based on natural gas resource, and oil (plus associated-dissolved gas) production is calculated based on the oil resource. Lease condensate production is separated from the natural 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.

Figure 3-3. Undiscovered field production profile



Source: ICF Consulting

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 2016 are included in this component of the OOGSS. The data required for these fields include location, field size class, natural gas percentage of BOE resource, condensate yield, natural gas-to-oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource 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).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2016 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100% oil, and a field that is announced as a natural gas field is assumed to be 100% natural gas. If a field is expected to produce both oil and natural gas, 70% is assumed to be oil and 30% is assumed to be natural gas.

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
Blacktip	AC380	6,234	2019	12	90	2027
Whale	AC772	8,799	2017	14	357	2024
Gotcha	AC856	7,713	2006	12	90	2028
Vicksburg B	DC353	7,500	2007	11	44	2026
Spruance	EW877	1,594	2019	11	44	2022
Sparta	GB959	4,498	2012	14	357	2027
Dothraki	GC166	2,234	2020	11	44	2030
Antrim	GC364	3,110	2018	11	44	2036
Khaleesi	GC389	3,602	2017	12	90	2022
Samurai	GC432	3,363	2009	12	90	2022
Mormont	GC478	3,799	2017	12	90	2022
Wildling Phase 2	GC520	4,117	2017	9	12	2034
Warrior	GC563	4,144	2016	11	44	2030
Shenzi North	GC609	4,295	2015	11	44	2024
Calpurnia	GC727	4,596	2017	12	90	2033
Mad Dog West & North	GC782	4,590	1998	11	44	2025
Anchor	GC807	5,184	2014	14	357	2024
Parmer	GC823	4,127	2003	11	44	2031
Argos Mad Dog Phase 2	GC825	5,899	2005	15	693	2022
Heidelberg Phase 2	GC859	5,869	2009	11	44	2040
Guadalupe	KC010	3,990	2014	13	176	2030
Tiber	KC102	4,131	2009	14	357	2040
Kaskida	KC292	5,860	2006	13	176	2034
Kaskida Phase 2	KC292	5,860	2006	13	176	2035
Leon	KC642	6,119	2014	12	90	2025
Castile	KC736	6,759	2011	10	23	2025
Buckskin South Phase 2	KC829	6,923	2009	13	176	2027
Horn Mountain West	MC126	5,420	2019	11	44	2022
Hoffe Park	MC166	4,019	2017	11	44	2031
Herschel Expansion	MC520	6,739	1997	10	23	2022
Rydberg	MC525	7,480	2014	12	90	2023
Fort Sumter	MC566	7,060	2016	12	90	2027
Ballymore	MC607	6,562	2018	14	357	2025
Dover	MC612	7,480	2018	12	90	2027
Taggart	MC816	5,741	2013	10	23	2022
Power Nap	MC943	4,173	2015	12	90	2022
Vito	MC984	4,091	2009	14	357	2023
Shenandoah Phase 1	WR052	6,037	2009	13	176	2024
Shenandoah Phase 2	WR052	6,037	2009	13	176	2029
North Yucatan	WR095	5,784	2013	12	90	2033
Coronado	WR098	6,129	2013	12	90	2033
Yeti	WR160	5,896	2015	11	44	2033
Monument	WR316	6,512	2020	12	90	2038
Julia Phase 2	WR627	7,218	2007	11	44	2033

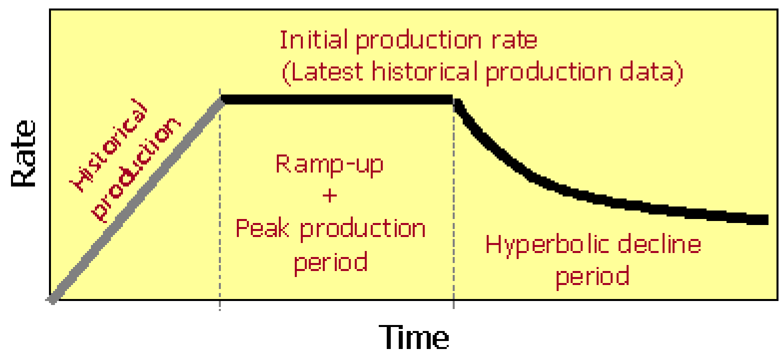
MMBOE = million barrels of oil equivalent.
Data source: U.S. Energy Information Administration, Office of Energy Analysis.

Producing fields component

A separate database is used to track currently producing fields. The data required for each producing field include location, field size class, field type (oil or natural gas), total recoverable resources, historical production (1990–2016), and hyperbolic decline parameters.

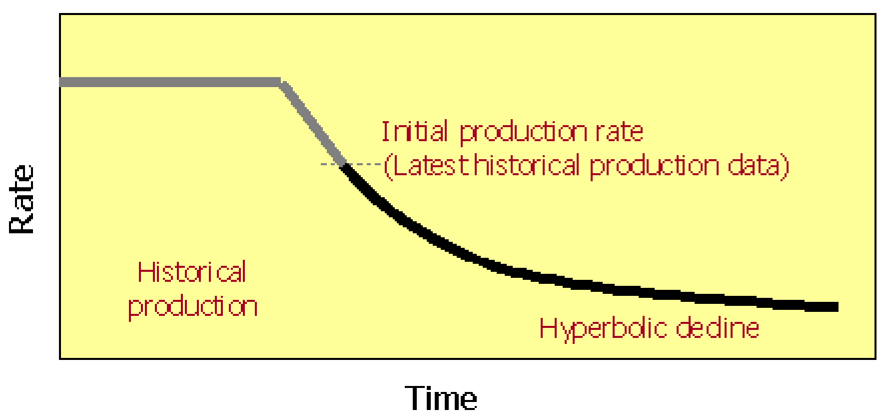
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number of ramp-up years and number of years at peak production, after which it will decline (Figure 3-5). The model assumes that production will decline according to 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 are determined in the same way as in the undiscovered field component.

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 and natural gas-producing fields

	Crude Oil						Natural Gas					
	FSC 2 – 10			FSC 11 - 17			FSC 2 – 10			FSC 11 - 17		
	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	1	0.15	3	4	0.1	2	1	0.3	3	2	0.3
Deep GOM	2	2	0.15	2	4	0.1	2	1	0.3	3	2	0.3
Atlantic	2	1	0.15	3	3	0.15	2	1	0.3	3	2	0.3
Pacific	2	1	0.1	3	2	0.1	2	1	0.3	3	2	0.1

Data source: ICF Consulting
Note: FSC = Field Size Class

Generation of supply curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in a given projection year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. For 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:

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \quad (3\text{-}18)$$

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 LFMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market-equilibrated volume passed to the OGSM from the NGMM.

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. Specifically:

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k} \right) \quad (3\text{-}19)$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k} \right) \quad (3\text{-}20)$$

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 natural gas)
r = region (1=Atlantic, 2=Pacific, 3=GOM)
k = fuel type (1=oil; 2=natural gas)
t = year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Because the expected offshore PR ratio is assumed to remain constant at the last historical value, the reserves needed to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Solving Equation 3-1 for $REVOFF_{r,k,t}$ and writing

$$RESOFF_{r,k,t+1} = EXPRDOFF_{r,k,t+1} / PR_{r,k}$$

gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t+1}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \quad (3\text{-}21)$$

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 NGMM.

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 considers the effect of 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 Level	Total Improvement (percent)	Number of Years
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

Data source: ICF Consulting

Appendix 3.A. Offshore data inventory

Variable name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
CPRDOFF	COPRD	Offshore coproduct rate	fraction	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
CUMDISC	DiscoveredFields	Cumulative number of discovered offshore fields	count	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	count	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial production to reserves ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
CURRESOFF	R	Offshore initial reserves	MMb Bcf	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
DECLOFF	--	Offshore decline rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
DEVLCOST	DevelopmentDrillingCost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dryhole 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, natural gas)
ELASTOFF	--	Offshore production elasticity values	fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingCosts	Exploration well drilling cost	$ per well	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	barrels, Mcf per year	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMb Bcf per well	4 Lower 48 offshore subregions; Fuel (oil, natural gas)

VARIABLES

Variable name				
Code	**Text**	**Description**	**Unit**	**Classification**
FR1OFF	FR1			
FR2OFF	FR3	Offshore developmental well finding rate	MMb Bcf per well	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMb Bcf per well	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMb Bcf	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
INFRSVOFF	I	Offshore inferred reserves	MMb Bcf	4 Lower 48 offshore subregions; Fuel (oil, natural 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	count	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 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 Natural Gas-Bcf per well	Offshore region; Offshore fuel (oil, gas)

VARIABLES

Variable Name				
Code	**Text**	**Description**	**Unit**	**Classification**
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMb per well Natural Gas-Bcf per well	Offshore region; Offshore fuel (oil, natural 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, natural gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMb per well Natural Gas-Bcf per well	Offshore region; Offshore fuel (oil, natural gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMb per well Natural Gas-Bcf per well	Offshore region; Offshore fuel (oil, natural 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, natural gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, natural 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	1987$	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
UNRESOFF	Q	Offshore undiscovered resources	MMb Bcf	4 Lower 48 offshore subregions; Fuel (oil, natural gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, natural gas)

VARIABLES

Variable Name Code	Text	Description	Unit	Classification
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, natural gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

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: NORTH CALIFORNIA; 10: CENTRAL CALIFORNIA; 11: SOUTH CALIFORNIA)	11
ntEU	Total number of evaluation units	46
nMaxEU	Maximum number of EU in a planning area (PA)	7
TOTFLD	Maximum number of fields to evaluate	6500
nANN	Total number of announce discoveries	70
nPRD	Total number of producing fields	1084
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

PARAMETERS

Parameter	Description	Value
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 facility water depth data points	11
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	1000
PRJLIFE	Maximum project life in years	10

Variable	Description	Unit	Source
ann_EU	Announced discoveries—Evaluation unit name	-	PGBA
ann_FAC	Announced discoveries—Type of production facility	-	BOEM
ann_FN	Announced discoveries—Field name	-	PGBA
ann_FSC	Announced discoveries—Field size class	integer	BOEM
ann_OG	Announced discoveries—Fuel type	-	BOEM
ann_PRDSTYR	Announced discoveries—Start year of production	integer	BOEM
ann_WD	Announced discoveries—Water depth	feet	BOEM
ann_WL	Announced discoveries—Number of wells	integer	BOEM
ann_YRDISC	Announced discoveries—Year of discovery	integer	BOEM
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	b/MMcf	BOEM

INPUT DATA

Variable	Description	Unit	Source
cstCap	Cost of capital	percentage	BOEM
dDpth	Drilling depth by PA, EU, FSC	feet	BOEM
deprSch	Depreciation schedule (eight-year schedule)	fraction	BOEM
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	BOEM
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	BOEM
devDrlDly24	Maximum number of development wells drilled from a 24-slot production facility 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$/well/year	BOEM
devTangFrc	Development wells tangible fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	BOEM
Drillcap	Drilling capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean exploratory well costs by region, water depth index, drilling depth index	million 2003 dollars	BOEM
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and delineation wells tangible fraction	fraction	ICF
fedTaxRate	Federal tax rate	percent	ICF
fldExpRate	Maximum field exploration rate	percent	ICF
gasprice	Natural gas wellhead price by region	2003$/Mcf	NGMM
gasSevTaxPrd	Natural gas production severance tax	2003$/Mcf	ICF

INPUT DATA

Variable	Description	Unit	Source
gasSevTaxRate	Natural gas severance tax rate	percent	ICF
GOprop	Natural gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Natural gas-to-oil ratio (Scf/b) by PA, EU	Scf/b	ICF
GORCutOff	GOR cutoff for oil/natural gas field determination	-	ICF
gRGCGF	Natural gas cumulative growth factor (CGF) for natural gas reserve growth calculation by year index	-	BOEM
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	PGBA
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	PGBA
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	PGBA
levExpSucRate	Seismic technology (increase exploration success rate)	percent	PGBA
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	PGBA
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	PGBA
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	PGBA
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	PGBA
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	PGBA
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
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-MMb per well Natural Gas-Bcf per well	calculated in model
nrdoff	New reserve discoveries by region and fuel type	Oil-MMb per well Natural Gas-Bcf per well	calculated in model

INPUT DATA

Variable	Description	Unit	Source
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$/b	ICF
oilprice	Oil wellhead price by region	2003$/b	LFMM
oilSevTaxPrd	Oil production severance tax	2003$/b	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil cumulative growth factor (CGF) for oil reserve growth calculation by year index	fraction	BOEM
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by planning area	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non-platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean production facility costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003$	BOEM
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	BOEM
prd_EU	Producing fields—Evaluation unit name	-	ICF
prd_FLAG	Producing fields—Production decline flag	-	ICF

INPUT DATA

Variable	Description	Unit	Source
prd_FN	Producing fields—Field name	-	BOEM
prd_ID	Producing fields—BOEM field ID	-	BOEM
prd_OG	Producing fields—Fuel type	-	BOEM
prd_YRDISC	Producing fields—Year of discovery	year	BOEM
prdDGasDecRatei	Initial natural gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Natural 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 natural 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 natural 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 natural gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of natural gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Natural gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial natural gas production (Mcf/day/well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel type	fraction	PGBA
prdoff	Expected production by fuel type	oil:Mb; natural 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 (b/day/well) by PA, EU	b/day/well	ICF
prod	Producing fields—Annual production by fuel type	oil:Mb; natural gas:MMcf	BOEM
prod_asg	AD gas production	Bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:Mb; natural 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	BOEM
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	BOEM

INPUT DATA

Variable	Description	Unit	Source
stTaxRate	Federal tax rate by PA, EU	percentage	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$/mile	BOEM
trnTrfGas	Natural gas pipeline tariff ($/Mcf) by PA, EU	2003$/b	ICF
trnTrfOil	Oil pipeline tariff ($/b) by PA, EU	2003$/b	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	BOEM
vMean	Geometric mean MMBOE of FSC	MMBOE	BOEM
vMin	Minimum MMBOE of FSC	MMBOE	BOEM
wDpth	Water depth by PA, EU, FSC	feet	BOEM
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF

Data sources: U.S. Energy Information Administration, Petroleum, Natural Gas, and Biofuels Analysis; Bureau of Ocean Energy Management (BOEM) (formerly the Minerals Management Service); ICF Consulting
Notes: MMB- Million barrels/day, bcf – billion cubic feet

4. Alaska Oil and Gas Supply Submodule

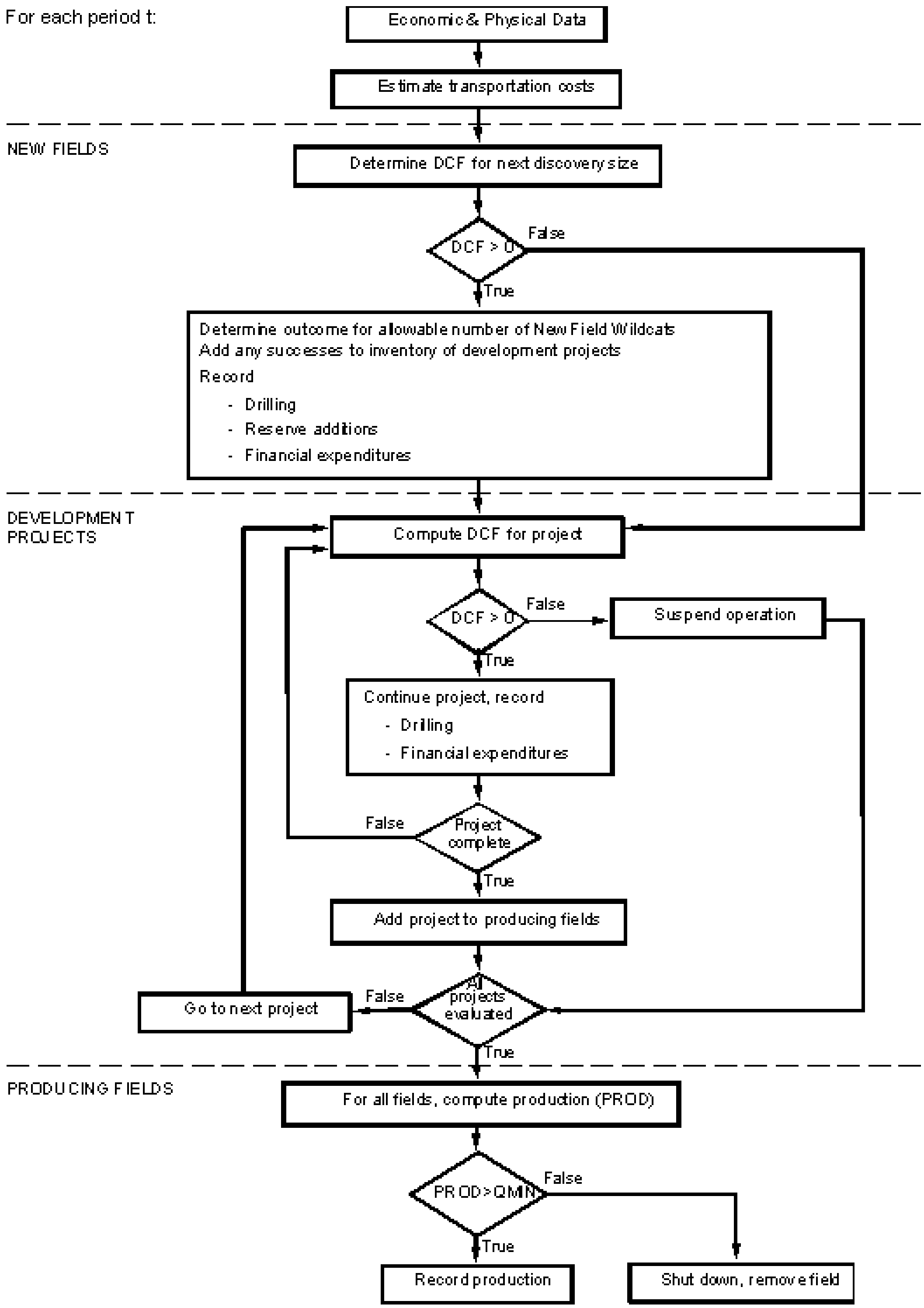
This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil production from the Onshore North Slope, Offshore North Slope, and Other Alaska areas (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Arctic National Wildlife Refuge area in the east. This section provides an overview of the basic modeling approach, including a discussion of the discounted cash flow (DCF) method.

Alaska natural gas production is not projected by the AOGSS but by the Natural Gas Transmission and Distribution Module (NGMM). The NGMM projects Alaska natural gas consumption and whether an Alaska natural gas pipeline is projected to be built to carry Alaska North Slope natural gas into Canada and U.S. natural gas markets. As of January 1, 2012, Alaska was estimated to have 10 trillion cubic feet of proved reserves plus 271 trillion cubic feet of unproved resources, excluding the Arctic National Wildlife Refuge undiscovered natural gas resources. Over the long term, Alaska natural gas production is determined and constrained by local consumption and by the capacity of a natural gas pipeline that might be built to serve Canada and U.S. Lower 48 markets. The proved and inferred natural gas resources alone, plus known but undeveloped resources, are sufficient to satisfy at least 20 years of Alaska's natural gas consumption and natural gas pipeline throughput. Large deposits of natural gas have been discovered along the North Slope (for example, Point Thomson) but remain undeveloped because of a lack of access to natural gas consumption markets. Because Alaska's natural gas production is best determined by projecting Alaska's natural gas consumption and whether a natural gas pipeline is put into operation, the AOGSS does not attempt to project new natural gas field discoveries and their development or the declining production from existing fields.

AOGSS overview

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected that exist onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1). Transportation costs are used with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow (DCF) calculation is used to determine the economic viability of Alaska's drilling and production activities. Oil field investment decisions are modeled on discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined on assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



As of January 1, 2012, Alaska's onshore and offshore technically recoverable oil resources equal 4 billion barrels of proved reserves plus 34 billion barrels of unproved resources.

Calculation of costs

Costs differ within the model for successful wells and dryholes. Costs are categorized functionally within the model as:

- Drilling costs
- Lease equipment costs
- 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 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 like those used for the Lower 48 states 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 dryholes 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 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:

$$\mathrm{DRILLCOST}_{i,r,k,t} = \mathrm{DRILLCOST}_{i,r,k,T_b} * (1 - \mathrm{TECH1}) ** (t - T_b) \qquad (4\text{-}1)$$

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, natural gas=2 - but not used)
t	=	projection year

DRILLCOST = drilling costs

T_b = base year of the projection

TECH1 = annual decline in drilling costs as a result of 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 drilling rig 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 drilling rigs are moved up to Alaska and reconfigured for Arctic conditions, they typically remain in Alaska. Company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of the limited number of drilling rigs and equipment available for use. Most Alaska oil rig activity pertains to drilling in-fill wells intended to slow the rate of production decline in the largest Alaska oil fields.

Alaska's onshore and offshore drilling and completion costs were updated in 2010 based on the American Petroleum Institute's (API) *2007 Joint Association Survey on Drilling Costs*, dated December 2008. Based on these API drilling and completion costs and earlier work performed by Advanced Resources International, Inc., in 2002, the following oil well drilling and completion costs were incorporated into the AOGSS database (Table 4.1).

Table 4-1. AOGSS oil well drilling and completion costs by location and category

	New Field Wildcat Wells	New Exploration Wells	Developmental Wells
	In millions of 1990 dollars		
Offshore North Slope	240	25	**20**
Onshore North Slope	202	15.3	**11.6**
South Alaska	**100**	**12**	**7.5**

Lease equipment costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a developed lease. Costs include producing equipment, the gathering system, processing equipment (for example, oil/natural gas/water separation), and production-related infrastructure such as gravel pads. Producing equipment costs include tubing and pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil well is:

$$\mathrm{EQUIP}_{r,k,t} = \mathrm{EQUIP}_{r,k,T_b} * (1 - \mathrm{TECH2})^{t-T_b} \quad (4\text{-}2)$$

where

r = region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)

k = fuel type (oil = 1, natural gas = 2 – not used)

t = projection year

EQUIP = lease equipment costs

T_b = base year of the projection

TECH2 = annual decline in lease equipment costs as a result of 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:

$$\mathrm{OPCOST}_{r,k,t} = \mathrm{OPCOST}_{r,k,T_b} * (1 - \mathrm{TECH2})^{t-T_b} \tag{4-3}$$

where

r = region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)

k = fuel type (oil = 1, natural gas = 2 – not used)

t = projection year

OPCOST = operating cost

T_b = base year of the projection

TECH3 = annual decline in operating costs as a result of 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 Alaska 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 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 dryhole 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 dryhole cost estimates are based on historical success rates of successful versus dryhole footage.
- Lease equipment for existing wells is in place before the first projection year of the model.

Discounted cash flow analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil projects.[11] A positive DCF is necessary to initiate the development of a discovered oil field. With all else being equal, large oil fields are more profitable to develop than small and mid-size fields. In Alaska, where developing new oil fields is quite expensive, particularly in the Arctic, the profitable development of small and mid-size oil fields generally depends on existing infrastructure that was paid for by the development of a nearby large field. So, AOGSS assumes that the largest oil fields will be developed first, followed by the development of ever-smaller oil fields. Whether these oil fields are developed, regardless of their size, is projected on 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 oil transportation cost to southern California refineries. Transportation costs for Alaska's oil include both pipeline and tanker shipment costs. The oil transportation cost directly affects the expected revenues from the production of a field:[12]

$$\mathrm{REV}_{f,t} = \mathrm{Q}_{f,t} * (\mathrm{MP}_t - \mathrm{TRANS}_t) \tag{4-4}$$

[11] See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[12] This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

where

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the Lower 48 states
TRANS	=	transportation cost.

The expected discounted cash flow associated with a potential oil project in field f at time t is given by:

$$\begin{aligned} DCF_{f,t} = (&PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ &- PVOPCOST - PVPRODTAX - PVSIT - PVFIT)_{f,t} \end{aligned} \quad (4\text{-}5)$$

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

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \quad (4\text{-}6)$$

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:

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}}. \quad (4\text{-}7)$$

The model assumes that the field with the highest positive PROF in time t is eligible for exploratory drilling in the same year. The profitability indexes for Alaska also are passed to the basic framework module of the OGSM.

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 field reserves requires both a successful new field wildcat well and a positive discounted cash flow of the costs relative to the revenues. The discovery procedure can be determined endogenously, based on exogenously determined data. The procedure requires the following exogenously determined data:

- New field wildcat success rate
- Any restrictions on the timing of drilling
- The distribution of technically recoverable field sizes within each region

- The endogenous procedure generates:

- The new field wildcat wells drilled in any year
- The set of individual fields to be discovered, specified based on size and location (relative to the three Alaska regions, in other words, offshore North Slope, onshore North Slope, and South Central Alaska)
- An order for the discovery sequence
- A schedule for the discovery sequence

The new field discovery procedure relies on the U.S. Geological Survey (USGS) and Bureau of Ocean Energy Management (BOEM) respective estimates of onshore and offshore technically recoverable oil resources as translated into the expected field size distribution of undiscovered fields. These onshore and offshore field size distributions are used to determine the field size and order of discovery in the AOGSS exploration and discovery process. So, the AOGSS oil field discovery process is consistent with the expected geology based on expected aggregate resource base and the relative frequency of field sizes.

AOGSS assumes that the largest fields in a region are found first, followed by successively smaller fields. This assumption is based on the following observations:

- The largest-volume fields typically encompass the greatest areal extent and so raise the probability of finding a large field relative to finding a smaller field.
- Seismic technology is sophisticated enough to determine the location of the largest geologic structures that might hold oil.
- Producers have a financial incentive to develop the largest fields first both because of their higher inherent rate of return and because the largest fields can pay for the development of expensive infrastructure to develop the smaller fields using that same infrastructure.
- Historically, North Slope and Cook Inlet field development has generally progressed from largest field to smallest field.

Onshore and offshore North Slope new field wildcat drilling activity is a function of the Brent crude oil price from 1977 through 2008, expressed in 2008 dollars. The new field wildcat exploration function was statistically estimated based on this price and on exploration well drilling data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) data files for the same period.[13] The North Slope wildcat exploration drilling parameters were estimated using ordinary least square methodology:

$$NAK\_NFW_t = \left(0.13856 * IT\_WOP_t\right) + 3.77 \tag{4-8}$$

where

t	=	year
NAK_NFW_t	=	North Slope Alaska field wildcat exploration wells
IT_WOP_t	=	World oil price in 2008 dollars

The summary statistics for the statistical estimation are as follows:

Dependent variable: NSEXPLORE
Current sample: 1 to 32
Number of observations: 32

Mean of dep. var.	=	9.81250	LM het. test	=	.064580 [.799]
Std. dev. of dep. var.	=	4.41725	Durbin-Watson	=	2.04186 [<.594]
Sum of squared residuals	=	347.747	Jarque-Bera test	=	.319848 [.852]
Variance of residuals	=	11.5916	Ramsey's RESET2	=	.637229E-04 [.994]
Std. error of regression	=	3.40464	F (zero slopes)	=	22.1824 [.000]
R-squared	=	.425094	Schwarz B.I.C.	=	87.0436
Adjusted R-squared	=	.405930	Log likelihood	=	-83.5778

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
C	3.77029	1.41706	2.66065	[.012]
WTIPRICE	.138559	.029419	4.70982	[.000]

Because very few offshore North Slope wells have been drilled since 1977, within AOGSS, the total number of exploration wells drilled on the North Slope is shared between the onshore and offshore regions. The wells are predominantly drilled onshore in the early years of the projections and progressively more wells are drilled offshore so that after 20 years, 50% of the exploration wells are drilled onshore and 50% are drilled offshore.

Based on the AOGCC data for 1977 through 2008, the drilling of South Central Alaska new field wildcat exploration wells was statistically unrelated to oil prices. On average, three exploration wells per year were drilled in South Central Alaska during the 1977 through 2008 timeframe, regardless of prevailing oil prices. This result probably stems from the facts that most of the South Central Alaska drilling activity is

[13] A number of alternative functional formulations were tested (for example, using Alaska crude oil prices, lagged oil prices, etc.), yet none of the alternative formations resulted in statistically more significant relationships.

focused on natural gas rather than oil and that natural gas prices are determined by the Regulatory Commission of Alaska rather than being *market driven*. So, AOGSS specifies that three exploration wells are drilled each year.

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 before the recovery of relatively small accumulations or heavy oil deposits. State and federal lease sale schedules could 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 the Arctic National Wildlife Refuge (ANWR) was permitted in 2021, then the earliest possible date at which an ANWR field could begin oil production would be in 2031.[14] Another example is the wide-scale development of the West Sak field that will be delayed until a technology can be developed that will enable the heavy, viscous 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 multiyear projects.

Each model year, the DCF is calculated for each potential development project. Initially, the model assumes a drilling schedule determined by the user or by some set of specified rules. However, if the DCF for a given project is negative, then development of this project is suspended in the year in which the negative DCF occurs. The DCF for each project is evaluated in subsequent years for a positive value. The model assumes that development would resume when a positive DCF value is calculated.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[15] The specific assumptions used in this work are:

- A two- to four-year build-up period from initial production to the peak production rate
- A peak production rate sustained from three to eight years
- A production rate that declines by 12% to 15% per year after peak production

The production algorithm build-up and peak-rate period are based on the expected size of the undiscovered field; larger fields have longer build-up and peak-rate periods than the smaller fields. The field production decline rates are also determined by the field size.

The pace of development and the ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (for example, API gravity).

[14] The earliest ANWR field is assumed to go into production 10 years after the first projection year.

[15] 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).

Producing fields

Oil production from fields producing as of the initial projection year (for example, Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) is based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on recent 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.[16] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the Lower 48 states.[17] The Prudhoe Bay Field is the largest known deposit of North Slope natural gas (24.5 Tcf),[18] and currently all of the natural gas produced from this field is re-injected to maximize oil production. Total known North Slope natural gas resources equal 35.4[19] Tcf. So, the undiscovered onshore central North Slope and NPRA technically recoverable natural gas resource base are respectively estimated to be 33.3 Tcf[20] and 52.8 Tcf.[21] Collectively, these North Slope natural gas reserves and resources equal 121.5 Tcf, which would satisfy the 1.64 Tcf per year natural gas requirements of an Alaska natural gas pipeline for almost 75 years, well after the end of the *Annual Energy Outlook* projections. So, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska natural gas pipeline during the *Annual Energy Outlook* projection period.

For the *Annual Energy Outlook 2012*, a new algorithm was added with respect to North Slope oil production. The new algorithm assumed the Alyeska Oil Pipeline (also known as the Trans Alaska Pipeline System, or TAPS) might be unable to operate at less than 350,000 barrels per day, if North Slope wellhead oil revenues were insufficient to pay for the pipeline upgrades necessary to keep the pipeline operating at low flow rates.

In August 2008, Alyeska initiated the Low Flow Impact Study (Study) that was released on June 15, 2011.[22] The Alyeska Study identified potential problems that might occur as TAPS throughput declines from the current production levels:

- Potential water dropout from the crude oil, which could cause pipeline corrosion
- Potential ice formation in the pipe if the oil temperature were to drop below freezing
- Potential wax precipitation and deposition

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[16] 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.

[17] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[18] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[19] Ibid.

[20] U.S. Geological Survey, *Oil and Gas Assessment of Central North Slope, Alaska, 2005*, Fact Sheet 2005–3043, April 2005, page 2, table – mean estimate total.

[21] U.S. Geological Survey, 2010 Updated Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska (NPRA), Fact Sheet 2010-3102, October 2010, Table 1 – mean estimate total, page 4.

[22] Alyeska Pipeline Service Company, *Low Flow Impact Study*, Final Report, June 15, 2011, Anchorage, Alaska, at

- Potential soil heaving
- Other potential operational issues at low flow rates, which include sludge dropout, reduced ability to remove wax, reduced pipeline leak detection efficiency, pipeline shutdown and restart, and the running of pipeline pigs that both clean and check pipeline integrity

- Although the onset of TAPS low flow problems could begin at about 550,000 barrels per day, absent any mitigation, the severity of the TAPS operational problems is expected to increase as throughput declines. As the types and severity of problems multiplies, the investment required to mitigate those problems is expected to increase significantly. Because of the many and diverse operational problems expected to occur at less than 350,000 barrels per day of throughput, considerable investment might be required to keep the pipeline operational below this threshold. Starting with AEO2012, it was assumed that the North Slope oil fields would be shut down, plugged, and abandoned if the following two conditions were simultaneously satisfied:

- TAPS throughput would have to be at or less than 350,000 barrels per day.
- Total North Slope oil production revenues would have to be at or less than $5.0 billion per year.

- In the year in which these two conditions were simultaneously satisfied, it was assumed that:

- TAPS would be decommissioned and dismantled.
- North Slope oil exploration and production activities would cease.

A more detailed discussion regarding these assumptions and their rationale is found in the AEO2012 report analysis entitled *Potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production* on pages 52 to 56 in the PDF version. As pointed out in the AEO2012 analysis, these two conditions are only satisfied in the Low Oil Price Case in 2026, when North Slope oil production and TAPS are shut down.

The determination of whether Alaska North Slope oil production is shut down during an *Annual Energy Outlook* projection is a two-step process. The first step is the determination of total onshore and offshore North Slope oil revenues. Total North Slope oil revenues equal onshore and offshore oil production multiplied by the result of a subtraction of the world oil price minus the transportation cost of shipping oil through TAPS and by tanker to West Coast refineries. The second step simultaneously compares whether total onshore and offshore oil production falls lower than the 350,000 barrels per day minimum TAPS throughput level and whether total onshore and offshore North Slope oil wellhead production revenues falls lower than the $5 billion per year minimum revenue threshold. If both conditions are simultaneously satisfied in any specific year, then TAPSFLAG variable is set to zero and onshore and offshore oil production levels are set to zero in that year and future years, precluding future North Slope oil production.

The total transportation cost of shipping oil from the North Slope depends on whether the oil is produced offshore or onshore; the offshore oil transportation cost is higher than the onshore transportation cost. Both the onshore and offshore transportation costs per barrel of oil are held constant throughout the projections, based on current TAPS and marine tanker transportation costs.

However, the per-barrel TAPS transportation cost would be expected to increase over time both because of declining TAPS throughput and because of higher total TAPS operation and maintenance costs as the pipeline ages and as the TAPS operator increasingly invests more money to mitigate the problems created by lower flow rates. So, TAPS and North Slope oil production could be shut down earlier than that projected in the Low Oil Price Case.

Appendix 4.A. Alaskan Data Inventory

Variable Name					
Code	Text	Description	Unit	Classification	Source
ANGTSMAX	--	Alaska Natural Gas Transportation System (ANGTS) maximum flow	Bcf/d	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/Mcf	Alaska	NPC
ANGTSRES	--	ANGTS reserves	Bcf	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	LTEM
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, natural gas)	LTEM
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, natural gas)	LTEM
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, natural gas)	LTEM
DRYAK	DRY	Alaska dryhole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, natural gas)	LTEM
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, natural gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	Wells per year	3 Alaska regions	LTEM
FACILAK	--	Alaska facility cost (oil field)	1990$/b	Field size class	USGS
FSZCOAK	--	Alaska oil field size distributions	MMb	3 Alaska regions	USGS

Variable Name					
Code	Text	Description	Unit	Classification	Source
FSZNGAK	--	Alaska natural gas field size distributions	Bcf	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	Mb/d	Field	AOGCC
KAPERCAK	EXKAP				
MAXPRO	--	Alaska maximum crude oil production	Mb/d	Field	Announced Plans
NAK_NFW	--	Number of new field wildcat wells drilling in Northern AK	Wells per year	NA	LTEM
NFW_AK	--	Alaska drilling schedule for new field wildcats	Wells	NA	LTEM
PRJAK	n	Alaska oil project life	Years	Fuel (oil, natural gas)	LTEM
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
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	LTEM
STTXAK	STRT	Alaska state tax rate	Fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	Fraction	Alaska	LTEM
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, natural gas)	LTEM
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	Fraction	Alaska	U.S. Tax Code

Data source: U.S. Energy Information Administration, Long-Term Energy Modeling (LTEM); National Petroleum Council (NPC), U.S. Geological Survey (USGS); Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen,[23] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, 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 (OSSS) 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. In one approach, which the majority of the oil companies pursued, the producer mines the oil shale rock in underground mines. A surface facility the retorts the rock to create bitumen, which is then further processed into syncrude. Occidental Petroleum Corp. pursued 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 heat the kerogen and convert it into bitumen, and the bitumen is 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.

When oil prices dropped to less than $15 per barrel in the mid-1990s, demonstrating an abundance of conventional oil supply, oil shale petroleum production became untenable and project sponsors canceled their oil shale research and commercialization programs. So, no commercial-scale oil shale production facilities were ever built or operated. So, the technical and economic feasibility of oil shale petroleum production remains untested and unproven.

In 1997, Shell Oil Company started testing a completely in-situ oil shale process, in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[24] are produced from separate production wells. The fully in-situ process has significant environmental and cost benefits relative to the other two approaches. The environmental benefits are lower water usage, no waste rock disposal, and the absence of hydrocarbon leaching from surface waste piles. As an example of the potential environmental impact on surface retorting, an industry using 25 gallon-per-ton oil shale rock to produce 2 million barrels per day would generate about 1.2 billion tons of waste rock per year, which is about 11% more than the weight of all the coal mined in the United States in 2010. Other advantages of the in-situ process include:

- Access to deeper oil shale resources

[23] Kerogen is a solid organic compound, which is also found in coal.
[24] Approximately, 30% naphtha, 30% jet fuel, 30% diesel, and 10% residual fuel oil.

- Greater oil and natural gas generated per acre because the process uses multiple oil shale seams within the resource column rather than just a single seam
- Direct production of petroleum products rather than syncrude that requires 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. Personnel safety would be greater and accident liability lower. Moreover, the in-situ process reduces the capital risk, because it involves building self-contained modular production units that can be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been commercially demonstrated, a substantial body of evidence already exists from field tests conducted by Shell Oil Company that the in-situ process is technologically feasible.[25] Shell is conducting additional tests to determine whether its in-situ process is commercially feasible.

Given the inherent cost and environmental benefits of the in-situ approach, other companies, including Chevron and ExxonMobil, are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being developed by companies such as Red Leaf Resources, the large-scale production of oil shale will most likely use the in-situ process. However, because in-situ oil shale projects have never been built, and because companies developing the in-situ process have not publicly released detailed technical parameters and cost estimates, the cost and operational parameters of such in-situ facilities is unknown. So, the 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 these processes so embody an environmental compliance cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the high expected cost structure of the underground mining/surface retorting facility constrains the initiation of oil shale project production, which should be viewed as a more conservative approach to simulating the market penetration of in-situ oil projects. On the other hand, OSSS oil shale facility costs are reduced by 1% per year to reflect technological progress, especially with respect to the improvement of an in-situ oil shale process. Finally, public opposition to building any type of oil shale facility is likely to be great, although the in-situ process is expected to be more environmentally benign than the predecessor technologies; the cost of building an in-situ oil shale facility is so likely to be considerably greater than would be determined strictly by the engineering parameters of such a facility.[26]

The OSSS only represents economic decision-making. In the absence of any existing commercial oil shale projects, it was impossible to determine the potential environmental constraints and costs of producing

[25] See *Shell's In-situ Conversion Process*, a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held October 16–18, 2006, in Boulder, Colorado.

[26] Project delays because of public opposition can significantly increase project costs and reduce project rates of return.

oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology, and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible. Whether domestic oil shale production reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. So, as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The 2-million-barrel-per-day production limit is based on an assessment of what is feasible given both the oil shale resource base and potential environmental constraints. [27] The 40-year minimum market penetration timeframe is based on the observation that "…an oil shale production level of 1 million barrels per day is probably more than 20 years in the future…"[28] with a linear ramp-up to 2 million barrels per day equating to a 40-year minimum.

The actual rate of market penetration in the OSSS largely depends on projected oil prices. Low prices result in low rates of market penetration, and the maximum penetration rate only occurs under high oil prices that result in high facility profitability. The development history of Canada's oil sands industry is an analogous situation. The first commercial Canadian oil sands facility began operations in 1967, the second project started operation in 1978, and the third project initiated production in 2003.[29] So even though the Canada's oil sands resource base is vast, it took over 30 years before a significant number of new projects were announced. This slow penetration rate, however, was largely caused by both the low world oil prices that persisted from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[30] The rise in oil prices that began in 2003 caused 17 new oil sands projects to be announced by year-end 2007.[31] Oil prices subsequently peaked in July 2008, and declined significantly, such that a number of these new projects were put on hold at that time.

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[27] *See* U.S. Department of Energy, *Strategic Significance of America's Oil Shale Resource,* March 2004, Volume I, page 23 – which speaks of an "aggressive goal" of 2 million barrels per day by 2020; and Volume II, page 7 – which concludes that the water resources in the Upper Colorado River Basin are "more than enough to support a 2 million barrel/day oil shale industry…"

[28] Source: RAND Corporation, "Oil Shale Development in the United States – Prospects and Policy Issues," MG-414, 2005, Summary page xi.

[29] The owner/operator for each of the three initial oil sands projects were respectively Suncor, Syncrude, and Shell Canada.

[30] Canada's first commercial oil sands facility started operations in 1967. It took 30 years later until the mid- to late 1990s for a building boom of Canada's oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[31] Source: Alberta Employment, Immigration, and Industry, *Alberta Oil Sands Industry Update*, December 2007, Table 1, pages 17 – 21.

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 petroleum 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.[32] So, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 timeframe 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.

For each projection year, the oil shale submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's projected crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, the submodule assumes that an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified by the market penetration algorithm. 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; second, by a determination of the number of oil shale projects that can be initiated in that year, based on the maximum total oil shale production level that is permitted by the market penetration algorithm.

In any one year, many oil shale projects can be initiated, raising the projected production rates in multiples of the rate for the standard oil shale facility, which is assumed to be 50,000 barrels per day, per project.

Since the development of the *Annual Energy Outlook 2012* (AEO2012), it was clear that oil industry investment was shifting from the development of oil shale production to tight oil production. Because tight oil production can be developed one well at a time, industry incremental investment costs are relatively low—between $5 million to $10 million per well. Because tight oil production typically begins about 60 days after drilling has begun, the time period between investment and production is relatively short. Finally, tight oil wells produce at very high initial rates, resulting in a rapid payback of investment capital and a relatively high rate of return on the investment. In contrast, oil shale projects require large initial investments and long construction lead times, which result in a slower rate of capital payback and lower rates of return. Because the size of the potential tight oil resource is quite large relative to projected domestic oil and natural gas production rates, the large-scale development of domestic oil shale resources appears to be indefinitely postponed. So, the model's Earliest Facility Construction Start Date is set to the year 2100, effectively precluding oil shale production during the projection period.

[32] 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.

Oil shale facility cost and operating parameter assumptions

The OSSS 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.[33] The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project and are inflated to constant 2004 dollars.[34] 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[35] because coal mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1% 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% lower in 2035 relative to the initial 2004 cost structure.

Although the Paraho cost structure might seem unrealistic, given 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, while there is no detailed public information regarding the expected cost of the in-situ process. Even though the in-situ process might be cheaper per barrel of output than the Paraho process, this difference should be weighed against the following facts:

- Oil and natural gas drilling costs have increased dramatically since 2005, somewhat narrowing that cost difference.
- The Paraho costs were determined at a time when environmental requirements were considerably less stringent.

So, 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; however, the Paraho process produces about the same volumes of oil and 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 cost 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 onsite is purchased from the local power grid at prevailing industrial prices. Both the natural gas produced and the electricity consumed are valued in the Net Present Value calculations at their respective regional prices, which are determined elsewhere in NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site

[33] 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.

[34] Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[35] 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 from $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, and 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 represents Arch Coal's average western underground mining cost.

consumption, building a separate on-site/off-site 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.[36] 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 because a carbon emissions allowance cost is embedded in the regional natural gas and electricity prices and costs.

OSSS oil shale facility configuration and costs

The OSSS facility parameters and costs are based on those reported for the Paraho Oil Shale project. Because the Paraho Oil Shale Project costs were reported in 1976 dollars, the OSSS costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices, electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. Based on the Paraho Oil Shale Project configuration, OSSS oil shale facility parameters and costs are listed in Table 5-1, along the OSSS variable names. For the *Annual Energy Outlook 2009* and subsequent outlooks, oil shale facility construction costs were increased by 50% to represent the world-wide increase in steel and other metal prices since the OSSS was initially designed. For the *Annual Energy Outlook 2011*, the oil shale facility plant size was reduced from 100,000 barrels per day to 50,000 barrels per day, based on discussions with industry representatives who believe that the smaller configuration was more likely for in-situ projects because this size captures most of the economies of scale while also reducing project risk.

Table 5-1. OSSS oil shale facility configuration and cost parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	**50,000 barrels per day**
Oil shale syncrude per ton of rock	OS_GAL_TON	**30 gallons**
Plant conversion efficiency	OS_CONV_EFF	**90%**
Average facility capacity factor	OS_CAP_FACTOR	**90% per year**
Facility lifetime	OS_PRJ_LIFE	**20 years**
Facility construction time	OS_PRJ_CONST	**3 years**
Surface facility capital costs	OS_PLANT_INVEST	**$2.4 billion (2004 dollars)**
Surface facility operating costs	OS_PLANT_OPER_CST	**$200 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% of syncrude value**
Carbon Dioxide Emissions Rate	**OS_CO2EMISS**	**150 metric tons per 50,000 b/d of production[37]**

[36] The Colorado/Utah/Wyoming region has relatively low electric power generation costs because of the low costs of mining Powder River Basin subbituminous coal and of existing electricity generation equipment, which is inherently lower than new generation equipment because of cost inflation and facility depreciation.
[37] Based on the average of the Fischer Assays determined for four oil shale rock samples of varying kerogen content. Op. cit. Noyes Data Corporation, Table 3.8, page 20.

The construction lead time for oil shale facilities is assumed to be three years, which is less than the five-year construction time estimates developed for the Paraho project. The construction period is shorter because drilling shallow in-situ heating and production wells can be accomplished much more quickly than erecting a surface retorting facility. 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 and that full capacity will be achieved in the second year of operation.

To mimic the fact that an industry's costs decline over time as a result of technological progress, better management techniques, and other factors, the OSSS initializes the oil shale facility costs in the year 2005 at the values shown above (in other words, surface facility construction and operating costs and underground mining costs). After 2005, these costs are reduced by 1% per year through 2035, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

OSSS oil shale facility electricity consumption and natural gas production parameters

Based on the Paraho Oil Shale Project parameters, Table 5-2 provides the level of annual natural gas production and annual electricity consumption for a 50,000 b/d project, operating at 100% capacity utilization for a full calendar year.[38]

Table 5-2. OSSS 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	**16.1 billion cubic feet per year**
Wellhead gas sales price	OS_GAS_PRICE	**Dollars per Mcf (2004 dollars)**
Electricity consumption	OS_ELEC_CONSUMP	**0.83 billion kilowatt-hours per year**
Electricity consumption price	**OS_ELEC_PRICE**	**Dollars per kilowatthour (2004 dollars)**

Project yearly cash flow calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation expenses, which are then discounted to a net present value. In those future years in which the net present value exceeds zero, a new oil shale facility can begin construction, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 23-year period, composed of 3 years for construction and 20 years for a plant's operating life. During the first 3 years of the 23-year period, only plant construction costs are considered, and the facility investment cost is evenly apportioned across the 3 years. In the fourth year, the plant goes into partial operation and produces 50% of the rated output. In the fifth year, revenues and operating expenses are assumed to ramp up to the full-production values, based on a 90% capacity factor that allows for potential production outages. During

[38] Op. cit. Noyes Data Corporation, pages 89-97.

years 4 through 23, total revenues equal oil production revenues plus natural gas production revenues.[39]

Discounted cash flow oil and natural gas revenues are calculated based on prevailing oil and natural gas prices projected for that future year. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil and natural gas at that time in the future and is *not* based either on historical price trends or future expected prices. Similarly, industrial electricity consumption costs are also based on the prevailing price of electricity for industrial consumers in that region at that future time.

As noted earlier, during a plant's first year of operation (year 4), both revenues and costs are half the values calculated for year 5 through year 23.

Oil revenues are calculated for each year t in the discounted cash flow:

$$\begin{aligned}\text{OIL\_REVENUE}_t = &\ \text{OIT\_WOP}_t * (1.083/0.732) * \text{OS\_PRJ\_SIZE} \\ &* \text{OS\_CAP\_FACTOR} * 365\end{aligned} \tag{5-1}$$

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
S_PROJ_PRJ_SIZE	=	Facility project size in barrels per day
OS_CAP_FACTOR	=	Facility capacity factor
365	=	Days per year.

Natural gas revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned}\text{GAS\_REVENUE}_t = &\ \text{OS\_GAS\_PROD} * \text{OGPRCL48}_t * 1.083/0.732) \\ &* \text{OS\_CAP\_FACTOR},\end{aligned} \tag{5-2}$$

where

OS_GAS_PROD	=	Annual natural gas production for 50,000-barrel-per-day facility
OGPRCL48_t	=	Natural gas price in Rocky Mountains 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.

Electricity consumption costs are calculated for each year in the discounted cash flow:

[39] 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 previous table regarding the volume of natural gas produced for a 50,000-barrel-per-day oil shale syncrude facility.

$$\text{ELECT\_COST}_t = \text{OS\_ELEC\_CONSUMP} * \text{PELIN}_t * (1.083/.732) * 0.003412 \\ * \text{OS\_CAP\_FACTOR} \tag{5-3}$$

where

OS_ELEC_CONSUMP	=	Annual electricity consumption for 50,000-barrel-per-day facility
PELIN_t	=	Electricity price Colorado/Utah/Wyoming at time t
(1.083 / .732)	=	Gross national product (GNP) chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

The carbon dioxide emission tax rate per metric ton is calculated:

$$\text{OS\_EMETAX}_t = \text{EMETAX}_t(1) * 1000.0 * (12.0 / 44.0) * (1.083 / .732) \tag{5-4}$$

where

$\text{EMETAX}_t(1)$	=	Carbon emissions allowance price/tax per kilogram at time t
1,000	=	Convert kilograms to metric tons
(12.0 / 44.0)	=	Atomic weight of carbon divided by atomic weight of carbon dioxide
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars.

Annual carbon dioxide emission costs per plant are calculated:

$$\text{CO2\_COST}_t = \text{OS\_EMETAX}_t * \text{OS\_CO2EMISS} * 365 * \text{OS\_CAP\_FACTOR} \tag{5-5}$$

where

OS_EMETAX_t	=	Carbon emissions allowance price/tax per metric ton at time t in 2004 dollars
OS_CO2EMISS	=	Carbon dioxide emissions in metric tons per day
365	=	Days per year
OS_CAP_FACTOR	=	Facility capacity factor

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t, \tag{5-6}$$

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:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{5-7}$$

Total project costs are calculated:

$$\begin{aligned} TOT\_COST_t = {} & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \tag{5-8}$$

where

$OS\_PLANT\_OPER\_CST$	=	Annual plant operating costs per year
$ROYALTY_t$	=	Annual royalty costs at time t
PRJ_MINE_COST	=	Annual plant mining costs
$ELEC\_COST_t$	=	Annual electricity costs at time t
$CO2\_COST_t$	=	Annual carbon dioxide emissions costs at time t
$INVEST_t$	=	Annual surface facility investment costs.

While the plant is under construction (years 1 through 3) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (years 4 through 23), the capital costs (INVEST) are zero, while the other five operating costs take on positive values. The annual investment cost for the three years of construction is calculated as follows, under the assumption that the construction costs are evenly spread over the three-year construction period:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{5-9}$$

where the variables are defined as in Table 5-1. Because the plant output is composed of both oil and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{5-10}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$\begin{aligned} PRJ\_MINE\_COST = {} & OS\_MINE\_CST\_TON * \frac{42}{OS\_GALLON\_TON * OS\_CONV\_EFF} \\ & * OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-11}$$

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

$$\begin{aligned} CASH\_FLOW_t = & \left(PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)\right) + \\ & (OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \end{aligned} \tag{5-12}$$

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%**
Equity share of total facility capital	OS_EQUITY_SHARE	**60%**
Facility equity beta	OS_EQUITY_VOL	**1.8**
Expected market risk premium	OS_EQUITY_PREMIUM	**6.5%**
Facility debt risk premium	**OS_DEBT_PREMIUM**	**0.5%**

The corporate equity beta (OS_EQUITY_VOL) is the 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. The median beta for oil and natural gas field exploration service firms is about 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.8.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.5%, 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 the Ba-rating range. Because the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the projection 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 projection 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 calculation of the discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through NEMS. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$\begin{aligned} \mathrm{OS\_DISCOUNT\_RATE}_t = &(((1-\mathrm{OS\_EQUITY\_SHARE})*(\mathrm{MC\_RMCORPBAA}_t/100+\\ &\mathrm{OS\_DEBT\_PREMIUM}))*(1-\mathrm{OS\_CORP\_TAX\_RATE})+\\ &(\mathrm{OS\_EQUITY\_SHARE}*((\mathrm{OS\_EQUITY\_PREMIUM}*\\ &\mathrm{OS\_EQUITY\_VOL})+\mathrm{MC\_RMGFCM\_10NS}_t/100)) \end{aligned} \tag{5-13}$$

where

OS_EQUITY_SHARE	=	Equity share of total facility capital
$\mathrm{MC\_RMCORPBAA}_t/100$	=	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
$\mathrm{MC\_RMGFCM\_10NS}_t/100$	=	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:

$$\mathrm{OS\_DISCOUNT\_RATE}_t = ((1.0+\mathrm{OS\_DISCOUNT\_RATE}_t)/(1.0+\mathrm{INFL}_t))-1.0 \tag{5-14}$$

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:

$$\mathrm{NET\_CASH\_FLOW}_{t-1} = \sum_{t=1}^{\mathrm{OS\_PRJ\_LIFE}+\mathrm{OS\_PRJ\_CONST}} \left[\mathrm{CASH\_FLOW}_t * \left[\frac{1}{1+\mathrm{OS\_DISCOUNT\_RATE}_t} \right]^t \right] \tag{5-15}$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil shale facility market penetration algorithm

As noted in the introduction, no empirical basis exists 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 three primary constraints to oil shale facility construction. First, the construction of an oil shale facility cannot be undertaken until the in-situ technology has been sufficiently developed and tested to be deemed ready for its application to commercial size projects (in other words, 50,000 barrels per day). Second, oil shale facility construction is constrained by the maximum oil shale production limit. Third, oil shale production volumes cannot reach the maximum oil shale production limit any earlier than 40 years after the in-situ technology has been deemed to be feasible and available for commercial-size facilities. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market penetration parameters

Market Penetration Parameters	OSSS Variable Name	Parameter Value
Earliest Facility Construction Start Date	OS_START_YR	**2100**
Maximum Oil Shale Production	OS_MAX_PROD	**2 million barrels per year**
Minimum Years to Reach Full Market Penetration	**OS_PENETRATE_YR**	**40**

As discussed in the introduction to this submodule, oil and natural gas industry interest in oil shale research, development, and production has waned in the face of the significantly greater rate-of-return opportunities associated with tight oil production. The development of large-scale oil shale production appears to be indefinitely postponed. So, the Earliest Facility Construction Start Date was set to the year 2100. This parameter change effectively precludes oil shale production during the projection period.

As discussed earlier, a 2-million-barrel-per-day oil shale production level at the end of a 40-year market penetration period is reasonable and feasible based on the size of the resource base and the volume and availability of water needed to develop those resources. The actual rate of market penetration in the OSSS, however, is ultimately determined by the projected profitability of oil shale projects. At a minimum, oil and natural gas prices must be sufficiently high to produce a facility revenue stream (in other words, the discounted cash flow) that covers all capital and operating costs, including the weighted average cost of capital. When the discounted cash flow exceeds zero (0), then the market penetration algorithm allows oil shale facility construction to commence.

When project discounted cash flow is greater than zero, the relative project profitability is calculated:

$$OS\_PROFIT_t = DCF_t \;/\; OS\_PLANT\_INVEST \tag{5-16}$$

where

DCF_t = Project discounted cash flow at time t
OS_PLANT_INVEST = Project capital investment

OS_PROFIT is an index of an oil project's expected profitability. The expectation is that, as OS_PROFIT increases, the relative financial attractiveness of producing oil shale also increases.

The level of oil shale facility construction that is permitted in any year depends on the maximum oil shale production that is permitted by the following market penetration algorithm:

$$\begin{aligned} MAX\_PROD_t = {} & OS\_MAX\_PROD * (OS\_PROFIT_t \;/\; (1 + OS\_PROFIT_t)) \\ & * ((T - (OS\_START\_YR - 1989)) \;/\; OS\_PENETRATE\_YR) \end{aligned} \tag{5-17}$$

where

OS_MAX_PROD = Maximum oil shale production limit
OS_PROFIT_t = Relative oil shale project profitability at time t
t = Time t
OS_START_YR = First year that an oil shale facility can be built
$OS\_PENTRATE\_YR$ = Minimum number of years during which the maximum oil shale production can be achieved.

The OS_PROFIT portion of the market penetration algorithm (5-24) rapidly increases market penetration as the DCF numerator of OS_PROFIT increases. However, as OS_PROFIT continues to increase, the rate of increase in market penetration slows as (OS_PROFIT / (1 + OS_PROFIT) asymptotically approaches one (1.0). As this term approaches 1.0, the algorithm's ability to build more oil shale plants is ultimately constrained by OS_MAX_PROD term, regardless of how financially attractive the construction of new oil shale facilities might be. This formulation also prevents MAX_PROD from exceeding OS_MAX_PROD.

The second portion of the market penetration algorithm specifies that market penetration increases linearly over the number of years specified by OS_PENETRATE_YR. As noted earlier OS_PENETRATE_YR specifies the minimum number of years over which the oil shale industry can achieve maximum penetration. The maximum number of years required to achieve full penetration is dictated by the speed at which the OS_PROFIT portion of the equation approaches one (1.0). If OS_PROFIT remains low, then it is possible that MAX_PROD never comes close to reaching the OS_MAX_PROD value.

The number of new oil shale facilities that start construction in any particular year is specified by the following equation where INT is a function that returns an integer:

$$\begin{aligned} OS\_PLANTS\_NEW_t = & \ INT((MAX\_PROD_t - (OS\_PLANTS_t * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) \\ & / (OS\_PRJ\_SIZE * OS\_CAP\_FACTOR)) \end{aligned} \tag{5-18}$$

where

MAX_PROD_t	=	Maximum oil shale production at time t
OS_PLANT_t	=	Number of existing oil shale plants at time t
OS_PRJ_SIZE	=	Standard oil shale plant size in barrels per day
OS_CAP_FACTOR	=	Annual capacity factor of an oil shale plant in percent per year.

The first portion of the above formula specifies the incremental production capacity that can be built in any year, based on the number of plants already in existence. The latter portion of the equation determines the integer number of new plants that can be initiated in that year, based on the expected annual production rate of an oil shale plant.

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 2 million barrels per day, which is approximately equivalent to 44 facilities of 50,000 barrels per day operating at a 90% capacity factor. So the algorithm allows enough plants to be built to fully reach the oil shale production limit, based on the expected plant capacity factor. As noted earlier, the oil shale market penetration algorithm is also limited by the earliest commercial plant construction date, which is assumed to be no earlier than 2017.

The OSSS costs and performance profiles are based on technologies evaluated in the 1970s and early 1980s, but the complete absence of any current commercial-scale oil shale 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 1970s, then the prospects for oil shale development would remain weak throughout the projections. However, technological progress can alter the economic and environmental landscape in unanticipated ways. For example, if an in-situ oil shale process were to be demonstrated to be both technically feasible and commercially profitable, then the prospects for an oil shale industry would improve significantly and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

6. Canadian Natural Gas Supply Submodule

Introduction

The Canadian Natural Gas Supply Submodule (CNGSS) is designed to project Canada's natural gas production. These volumes are passed to the NGMM and are used in determining Canada's imports to the United States as a result of the North American market equilibration that occurs in the NGMM. LNG imports into Canada also are determined in the NGMM.

Canada's natural gas production is represented for two regions—Western Canada (Alberta, British Columbia, and Saskatchewan) and Eastern Canada (Nova Scotia, New Brunswick, Ontario, Yukon, and Northwest Territories). Production from Western Canada is further disaggregated into natural gas associated-dissolved with crude oil (AD gas) and nonassociated conventional, tight, shale, and coalbed methane (CBM). Western Canadian AD gas production and all natural gas production from the Eastern Canada region are set exogenously and are a user-specified input to the CNGSS. Natural gas production from the Mackenzie Delta is dependent on the construction of a pipeline to Alberta and is determined in the Natural Gas Markets Module (NGMM).

Western Canada

The approach taken to determine Western Canada's nonassociated 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 the Western Canada's natural gas wellhead price, rather than as a function of expected profitability. Next, a production profile is applied to the successful wells to determine expected nonassociated natural gas production from new wells. Nonassociated natural gas production from old wells (legacy production) is based on the Canada Energy Regulator (CER) report, *Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050*.[40] The sum of legacy and new well production gives the total expected nonassociated natural gas production potential from Western Canada.

The Western Canada regional, well-type categories are:

- Alberta conventional gas
- Alberta tight gas
- Alberta shale gas
- Alberta CBM
- British Columbia conventional gas
- British Columbia tight gas
- British Columbia shale gas
- British Columbia CBM
- Saskatchewan conventional gas
- Saskatchewan tight gas

[40] Canada Energy Regulator, *Canada's Energy Future 2020: Energy Supply and Demand Projections to 2050*, https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2020/

Drilling determination

The total number of successful natural gas wells drilled in Western Canada each year is based on the Reference case projection in the CER report and is calculated as a function of the Canadian natural gas wellhead price as follows:

$$CNWELLS_{r,t} = [C_r + A1_r * t + A2_r * t^2 + A3_r * t^3] * CNNGPRC_t * \left[\frac{BRENT\_PRICE_t}{CNBASEWOP_t}\right]^{CNDRL\_OPRC_r}, \tag{6-1}$$

where

$CNWELLS_{r,t}$	=	number of successful Canadian wells drilled in year t
$C_r, A1_r, A2_r, A3_r$	=	regional coefficients
$CNNGPRC_t$	=	Canadian natural gas wellhead price
$BRENT\_PRICE_t$	=	Brent spot price
$CNBASEWOP_t$	=	Brent spot price assumed in the CER report
$CNDRL\_OPRC_r$	=	Oil price elasticity
r	=	regional, well-type category
t	=	year index (t=1 for year 2016).

Nonassociated natural gas production

Nonassociated natural gas production is categorized into production from old wells (legacy) and production from new wells. Legacy production through the projection period is determined exogenously and is a user input to the CNGSS.

Natural gas production from each new natural gas well is determined by the following hyperbolic function:

$$WLprd_{r,t} = \frac{CNPRD\_Q0_r}{(1+CNPRD\_Di_r*CNPRD\_b_r*t)^{1/CNPRD\_b_r}}, \tag{6-2}$$

where

$WLprd_{r,t}$	=	annual well-level nonassociated natural gas production
$CNPRD\_Q0_r$	=	Initial production rate
$CNPRD\_Di_r$	=	Initial decline rate
$CNPRD\_b_r$	=	Hyperbolic parameter (degree of curvature of the line)
r	=	regional well-type category
t	=	time (t=1 for first year of production).

Total Western Canadian nonassociated natural gas production is then determined by the following:

$$NAGPRD_{r,y} = LegacyPrd_{r,y} + \sum_{t=1}^{y} CNWELLS_{r,t} * WLprd_{r,y-t+1}\ , \tag{6-3}$$

where

$NAGPRD_{r,y}$ = Western Canadian nonassociated natural gas production

$LegacyPrd_{r,y}$ = legacy production from old wells in region r and year y

r = regional well-type category

y = year (y=1 for year 2016).

The Canadian production volumes are passed to the NGMM and used in the North American market equilibration that occurs in the NGMM to determine the level of Canadian natural gas imports to the United States.

Appendix 6.A. Canada data inventory

Variable Name					
Code	Text	Description	Unit	Classification	Source
CNADGEL	--	Elasticity for AD gas production	fraction	region, area, year	LTEM
CNADGPRD	--	AD gas production	Bcf	region	CER
CNBASEHH	--	Benchmark Henry Hub price	U.S. $/MMBtu	year	CER
CNBASEPRD	--	Baseline natural gas production	Bcf/year	area, fuel category, year	CER
CNBASEWOP	CNBASEWOP	Benchmark Brent price	U.S. $/b	year	CER
CNBASEYR	--	Canada base year	integer	--	LTEM
CNDRL_A1	A1	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_A2	A2	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_A3	A3	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_A4	A4	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_C	C	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_OPRCH	CNDRL_OPRC	Drilling equation parameter	fraction	area, fuel category	LTEM
CNDRL_OPRCL	CNDRL_OPRC	Drilling equation parameter	fraction	area, fuel category	LTEM
CNENAGPRD	--	Expected NA gas production	Bcf	region	LTEM
CNNGPRC	CNNGPRC	Canadian wellhead price	$/Mcf	region	LTEM
CNPRCDIFF	--	Canadian wellhead to Henry Hub price differential	$/Mcf	region	LTEM
CNPRD_B	CNPRD_B	Curvature parameter	fraction	area, fuel category	LTEM
CNPRD_DI	CNPRD_DI	Initial decline rate parameter	fraction	area, fuel category	LTEM
CNPRD_Q0	CNPRD_Q0	Initial flow rate parameter	fraction	area, fuel category	LTEM
CNRNAGPRD	--	Realized NA gas production	Bcf	region	LTEM
CNTRR	--	Technically recoverable natural gas resources	Tcf	area	CER

Data source: U.S. Energy Information Administration, Office of Long-Term Energy Modeling (LTEM) and Canada Energy Regulator (CER)

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 multiyear capital investments (for example, offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or natural 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 (for example, 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 natural gas project are generated from the production and sale of both the primary fuel and 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[41] times expected production[42] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), in other words, a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$\mathrm{WACC} = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{A-2}$$

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, 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

$$\mathrm{disc} = \frac{(1+\mathrm{WACC})}{(1+\pi_e)} - 1 \tag{A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the projection period is measured as the average annual rate of change in the U.S. GDP deflator over the projection period, using the projections of the GDP deflator from the Macroeconomic Activity Module (MC_JPGDP).

For all AEOs published in 2021 and later, the discount rate used to determine the profitability of a project is WACC plus 5%. This adder is used to account for an expected needed return over the cost of capital given producers' desire to improve their balance sheets and provide better returns to stakeholders as well as the general uncertainty in the global oil and natural gas markets due to the COVID19 pandemic.

The present value of expected revenue for either the primary fuel or its co-product is calculated as:

$$\mathrm{PVREV}_{T,k} = \sum_{t=T}^{T+n} \left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+\mathrm{disc}} \right]^{t-T} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ \mathrm{COPRD} \text{ if secondary fuel} \end{cases} \tag{A-4}$$

[41] 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.

[42] Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

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.[43]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and natural 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.

The present value of the total expected revenue generated from the representative project is

$$\mathrm{PVTREV_T = PVREV_{T,1} + PVREV_{T,2}} \tag{A-5}$$

where

$\mathrm{PVREV_{T,1}}$	=	present value of expected revenues generated from the primary fuel
$\mathrm{PVREV_{T,2}}$	=	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

$$\mathrm{PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2}} \tag{A-6}$$

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

$$\begin{aligned}\mathrm{PVPRODTAX_T} &= \mathrm{PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2}} \\ &\quad \mathrm{*(1 - ROYRT_2) * PRODTAX_2}\end{aligned} \tag{A-7}$$

[43] 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.

where

$$\text{PRODTAX} = \text{production tax rate.}$$

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 dryholes. The present value calculations of the expected costs are computed in a similar manner as PVREV (in other words, 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 dryholes and for equipping successful wells through the Christmas tree installation.[44] Elements 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. The present value of expected drilling costs is given by:

$$\begin{aligned}\text{PVDRILLCOST}_T = \sum_{t=T}^{T+n} \Bigg[\Big[& \text{COSTEXP}_T * \text{SR}_1 * \text{NUMEXP}_t + \text{COSTDEV}_T * \text{SR}_2 * \text{NUMDEV}_t \\ & + \text{COSTDRY}_{T,1} * (1 - \text{SR}_1) * \text{NUMEXP}_t \\ & + \text{COSTDRY}_{T,2} * (1 - \text{SR}_2) * \text{NUMDEV}_t \Big] * \left(\frac{1}{1 + \text{disc}} \right)^{t-T} \Bigg]\end{aligned}$$

(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 dryhole (1=exploratory, 2=developmental)

[44]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

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 an oil or natural gas project are supplied as part of the assumed production profile and are 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

$$\mathrm{PVEQUIP}_T = \sum_{t=T}^{T+n}\left[\mathrm{EQUIP}_t * (\mathrm{SR}_1 * \mathrm{NUMEXP}_t + \mathrm{SR}_2 * \mathrm{NUMDEV}_t) * \left[\frac{1}{1+\mathrm{disc}}\right]^{t-T}\right] \tag{A-9}$$

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

$$\mathrm{PVKAP}_T = \sum_{t=T}^{T+n}\left[\mathrm{KAP}_t * \left[\frac{1}{1+\mathrm{disc}}\right]^{t-T}\right] \tag{A-10}$$

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. So, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_t * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1 + disc} \right)^{t-T} \right]$$

(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

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_t * \left[\frac{1}{1 + disc} \right]^{t-T} \right] \tag{A-12}$$

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,[45]depreciable, or expensed costs according to current tax laws. All dryhole and operating costs are expensed. Lease costs (in other words, 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 (IDCs) (expensed). IDCs include wages, fuel, transportation, supplies, site preparation, development, and

[45] The DCF methodology does not include lease acquisition or geological and geophysical expenditures because they are not relevant to the incremental drilling decision.

repairs. Depreciable costs are 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
- Depreciation schedules shifted to a Modified Accelerated Cost Recovery System

Tax provisions vary with type of producer (major, large independent, or small independent) (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 natural gas producer or owner of an interest in oil and natural gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and natural 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:

$$\begin{aligned} \mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \Big[\big(&\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t \\ &-\mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t\big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \Big] \end{aligned} \tag{A-13}$$

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[46]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dryhole costs
disc	=	expected discount rate.

[46] This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

$TREV_t$, ROY_t, $PRODTAX_t$, $OPCOST_t$, and $ABANDON_t$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for the purpose of determining corporate income tax liability at the state and federal level.

Expected expensed costs

Expensed costs are intangible drilling costs, dryhole 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 fact is not true across the producer category (Table A-1). 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 natural gas production by category of company under current tax legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	Cost Depletion	Cost Depletion[b]	Maximum of Percentage or Cost Depletion
	G&G[a]	G&G	G&G
	Lease Acquisition	Lease Acquisition	Lease Acquisition
Depreciable Costs	MACRS[c]	MACRS	MACRS
	Lease Acquisition	Lease Acquisition	Lease Acquisition
	Other Capital Expenditures	Other Capital Expenditures	Other Capital Expenditures
	Successful Well Drilling Costs Other than IDCs	Successful Well Drilling Costs Other than IDCs	Successful Well Drilling Costs Other than IDCs
	Five-Year SLM[d] 30% of IDCs		
Expensed Costs	Dryhole Costs	Dryhole Costs	Dryhole Costs
	70% of IDCs	100% of IDCs	100% of IDCs
	Operating Costs	Operating Costs	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 IDCs are defined as follows:

$$\begin{aligned} \mathrm{XIDC_t} = {} & \mathrm{COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t} \\ & \mathrm{+COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t} \end{aligned} \tag{A-14}$$

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[47]
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 IDCs are expensed (as is the case for major producers), the remaining IDCs must be depreciated. The model assumes that these costs are recovered at a rate of 10% in the first year, 20% annually for four years, and 10% in the sixth year; this method of estimating the costs is referred to as the five-year Straight Line Method (SLM) with half-year convention. If depreciable costs accrue when fewer than six years remain in the life of the project, the recovered costs are estimated using a simple straight line method over the remaining period.

So, the value of expected depreciable IDCs is represented by

$$\begin{aligned} \mathrm{AIDC_t} = \sum_{j=\beta}^{t} \Big[& \Big(\mathrm{COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j} \\ & \mathrm{+COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j}\Big) \\ & \mathrm{*DEPIDC_t} * \left(\frac{1}{1+\mathrm{infl}}\right)^{t-j} * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-j} \Big], \end{aligned} \tag{A-15}$$

$$\beta = \begin{cases} \mathrm{T} \ \text{ for } \mathrm{t \le T + m - 1} \\ \mathrm{t - m + 1} \ \text{ for } \ \mathrm{t > T + m - 1} \end{cases}$$

[47] 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.

where

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t # n+T-m, five-year SLM recovery schedule with half-year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[48]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default because the DCF methodology reflects the tax treatment pertaining to large independent producers.

Expected dryhole costs

All dryhole costs are expensed. Expected dryhole costs are defined as

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \tag{A-16}$$

where

COSTDRY	=	drilling cost for a dryhole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

[48] The write-off schedule for the five-year SLM gives recovered amounts in nominal dollars. So, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars because the DCF calculation is based on constant-dollar values for all other variables.

Table A-2. MACRS schedules

percentage

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

Data source: U.S. Master Tax Guide

Expected depreciable tangible drilling costs, lease equipment costs, and other capital expenditures

Amortization of depreciable costs, excluding capitalized IDCs, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in 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 # n+T-m, MACRS with half-year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[49]
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:

[49] Each of the write-off schedules give recovered amounts in nominal dollars. So, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars because the DCF calculation is based on constant-dollar values for all other variables.

$$PVSIT_T = PVTAXBASE_T * STRT \tag{A-18}$$

where

PVTAXBASE = present value of expected taxable income (Equation A.14)
STRT = state income tax rate.

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 natural 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 effect 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 natural gas projects. Various types of oil and natural gas projects are evaluated using the proposed DCF calculation, including single-well projects and multiyear investment projects. Revenues generated from the production and sale of co-products also are considered.

The DCF routine requires important assumptions, such as assumed 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 project under consideration.

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Appendix C. Model Abstract

- Model name

    Oil and Gas Supply Module

Acronym

    OGSM

Description

    OGSM projects the following aspects of the crude oil and natural gas supply industry:

- U.S. production
- U.S. resources
- U.S. drilling activity
- Canadian natural gas production

Purpose

    OGSM is used by the Office of Energy Analysis 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.

Date of last update

    2023

Part of another model

    National Energy Modeling System (NEMS)

Model Interface References
Coal Market Module
Electricity Market Module
Industrial Demand Module
International Energy Module
Natural Gas Markets Module (NGMM)
Macroeconomic Activity Module
Liquid Fuels Market Module (LFMM)

Official model representative
Office: Long-Term Energy Modeling
Model Contact: William Sommer
Telephone: (202) 287-5826

Documentation reference

U.S. Department of Energy. 2020. Documentation of the Oil and Gas Supply Module (OGSM), DOE/EIA M063, U.S. Energy Information Administration, Washington, DC.

Archive media and installation manual
NEMS2023

Energy Systems Described

The OGSM projects oil and natural gas production activities for seven onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling activities are treated separately, and exploratory drilling is 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 that was never productive before. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proved 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.

Coverage
Geographic: Seven Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
Time Units/Frequency: Annually 1990 through 2050
Products: Crude oil and natural gas
Economic Sectors: Crude oil and natural gas field production activities

7. Model features
   Model Structure: Modular, containing five major components:

- Onshore Lower 48 Oil and Gas Supply Submodule
- Offshore Oil and Gas Supply Submodule
- Alaska Oil and Gas Supply Submodule
- Oil Shale Supply Submodule
- Canadian Natural Gas Supply Submodule

Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are projected using the estimated 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 NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

8. 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 (1970-2008), Washington, D.C.; (2) Additional unconventional gas recovery drilling and operating cost data from operating companies
- Offshore Technically Recoverable Oil and Natural 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 natural gas data from operating companies
- Unconventional Gas Technology Parameters—(1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

9. 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 (1980–2008), DOE/EIA-0815(80-08)
- Onshore Operating Cost—U.S. Energy Information Administration, Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980–2008), DOE/EIA-0815(80-08)
- Emissions Factors—U.S. Energy Information Administration

- Oil and Natural Gas Well Initial Flow Rates—U.S. Energy Information Administration, Office of Petroleum, Biofuels, and Natural Gas Analysis
- Wells Drilled—U.S. Energy Information Administration, Office of Energy Statistics
- Expected Recovery of Oil and Natural Gas Per Well—U.S. Energy Information Administration, Office of Petroleum, Biofuels, and Natural Gas Analysis
- Oil and Natural Gas Reserves—U.S. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, (1977–2011), DOE/EIA-0216(77–11)

10. Computing Environment

- Hardware Used: PC
- Operating System: UNIX simulation
- Language/Software Used: Fortran
- Memory Requirement: Unknown
- Storage Requirement: Unknown
- Estimated Run Time: 300 seconds

11. 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)

12. Status of Evaluation Efforts
    Not applicable

13. Bibliography
    See Appendix B of this document.

Appendix D. Output Inventory

Variable Name	Description	Unit	Classification	Passed To Module
OGCCAPPRD	Coalbed methane production from CCAP		17 OGSM/NGMM regions	NGMM
OGCNQPRD	Canadian production of oil and natural gas	Oil: MMb Gas: Bcf	Fuel (oil, natural gas)	NGMM
OGCNPPRD	Canadian price of oil and natural gas	Oil: 1987$/b Gas: 1987$/Bcf	Fuel (oil, natural gas)	NGMM
OGCO2AVL	CO2 volumes available	MMcf	7 OLOGSS regions 13 CO2 sources	EMM
OGCO2PRC	CO2 price	$/Mcf	7 OLOGSS regions 13 CO2 sources	EMM
OGCO2PUR	CO2 purchased from available sources	MMcf	7 OLOGSS regions 13 CO2 sources	EMM
OGCO2PUR2	CO2 purchased at the EOR site	MMcf	7 OLOGSS regions 13 CO2 sources	EMM
OGCO2TAR	CO2 transport price for interregional flows	$/Mcf	7 OLOGSS regions	EMM
OGCOPRD	Crude production by oil category	MMb/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMb/day	Shallow and deep water regions	Industrial
OGCORSV	Crude reserves by oil category	Barrel	5 crude production categories	Industrial
OGCOWHP	Crude wellhead price by oil category	1987$/b	10 OGSM reporting regions	Industrial
OGCRDHEAT	Heat rate by type of crude oil		9 crude types	LFMM
OGCRDPRD	Crude oil production by OGSM region and crude type	MMb/day	13 OGSM regions 9 crude types	LFMM
OGCRUDEREF	Crude oil production by LFMM region and crude type	MMb/day	LFMM regions 9 crude types	LFMM
OGDNGPRD	Dry gas production	Bcf	57 Lower 48 onshore & 6 Lower 48 offshore districts	LFMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGEORPRD	EOR production from CO2 projects	Mb	7 OLOGSS regions 13 CO2 sources	LFMM
OGEOYAD	Unproved associated-dissolved gas resources	Tcf	6 Lower 48 onshore regions	Main

Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSVON	Lower 48 Onshore proved reserves by category	Tcf	6 Lower 48 onshore regions 5 natural gas categories	Main
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: billion barrel Natural Gas: Tcf	6 Lower 48 onshore & 3 Lower 48 offshore regions	Main
OGEOYRSV	Proved crude oil and natural gas reserves	Oil: billion barrels Natural Gas: Tcf	6 Lower 48 onshore & 3 Lower 48 offshore regions	Main
OGEOYUGR	Technically recoverable unconventional gas resources	Tcf	6 Lower 48 onshore & 3 Lower 48 offshore regions	Main
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: billion barrels Natural Gas: Tcf	6 Lower 48 onshore & 3 Lower 48 offshore regions	Main
OGGROWFAC	Factor to reflect expected future cons growth	Fraction	NA	NGMM
OGJOBS	Number of oil and natural gas extraction jobs	thousands	NA	Macro
OGNGLAK	Natural gas liquids from Alaska	Mb/day	NA	LFMM
OGNGPLPRD	Natural gas plant liquids production	MMb/day	57 Lower 48 onshore & 6 Lower 48 offshore districts	LFMM
OGNGPRD	Natural gas production by 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 category	Tcf	12 oil and natural gas categories	NGMM
OGNGWHP	Natural gas wellhead price by category	1987$/Mcf	10 OGSM reporting regions	OGSM
OGNOWELL	Wells completed	Wells	NA	OGSM
OGPCRWHP	Crude average wellhead price	1987$/b	NA	OGSM
OGPNGWHP	Average natural gas wellhead price	1987$/b	NA	OGSM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGMM
OGPRCOAK	Alaskan crude oil production	Mb	3 Alaska regions	NGMM
OGPRDADOF	Offshore AD gas production	Bcf	3 Lower 48 offshore regions	NGMM
OGPRDADON	Onshore AD gas production	Bcf	17 OGSM/NGMM regions	NGMM

Variable Name	Description	Unit	Classification	Passed To Module
OGPRDUGR	Lower 48 unconventional natural gas production	Bcf	6 Lower 48 regions and 3 unconventional gas types	NGMM
OGPRRCAN	Canadian P/R ratio	Fraction	Fuels (oil, natural gas)	NGMM
OGPRRCO	Oil P/R ratio	Fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	OGSM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	Fraction	3 Lower 48 offshore regions	NGMM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	Fraction	17 OGSM/NGMM regions	NGMM
OGQCRREP	Crude production by oil category	MMb	5 crude production categories	OGSM
OGQCRRSV	Crude reserves	Billion barrels	NA	OGSM
OGQNGREP	Natural gas production by category	Tcf	12 oil and natural gas categories	NGMM Macro
OGQNGRSV	Natural gas reserves	Tcf	NA	OGSM
OGQSHLGAS	Natural gas production from select shale gas plays	Bcf	NA	OGSM
OGQSHLOIL	Crude oil production from select tight oil plays	MMb	NA	OGSM
OGRADNGOF	Nonassociated dry gas reserve additions, offshore	Bcf	3 Lower 48 offshore regions	NGMM
OGRADNGON	Nonassociated dry gas reserve additions, onshore	Bcf	17 OGSM/NGMM regions	NGMM
OGREGPRD	Crude oil and natural gas production	Oil: MMb Natural gas: Bcf	6 Lower 48 onshore regions 7 fuel categories	Industrial
OGRESCO	Oil reserves	MMb	6 Lower 48 onshore & 3 Lower 48 offshore regions	OGSM
OGRESNGOF	Offshore nonassociated dry gas reserves	Bcf	3 Lower 48 offshore regions	NGMM
OGRESNGON	Onshore nonassociated dry gas reserves	Bcf	17 OGSM/NGMM regions	NGMM
OGSHALENG	Natural gas produced from oil shale	Bcf	NA	NGMM
OGTAXPREM	Canadian tax premium	Oil: MMb Natural gas: Bcf	Fuel (oil, natural gas)	NGMM
OGWELLSL48	Lower 48 drilling (successful + dry)		10 OGSM reporting regions, 7 fuel categories	Industrial
OGWPTDM	Natural gas wellhead price	1987$/Mcf	17 OGSM/NGMM regions	NGMM