Documentation of the Oil and Gas Supply Module (OGSM)

October 2008

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

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2008*. These changes include:

- Re-estimation of lower 48 onshore drilling, lease equipment, and operating costs

- Re-estimation of lower 48 unconventional natural gas drilling levels and production-to-reserves ratios

- Re-estimation of lower 48 associated/dissolved gas reserve additions and production

- Incorporation of supply curves for carbon dioxide related enhanced oil recovery projects

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

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1. Introduction

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

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

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

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

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

OGSM is archived as part of the National Energy Modeling System (NEMS). The archival package of NEMS is located under the model acronym NEMS2008. The NEMS version documented is that used to produce the *Annual Energy Outlook 2008 (AEO2008)*. The package is available through the National Technical Information Service. The model contact for OGSM is:

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This OGSM documentation report presents the following major topics concerning the model.

- Model purpose

- Module structure

- Inventory of input data, parameter estimates, and model output

2. Model Purpose

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

The basic interaction between OGSM and the other oil and gas modules is represented in Figure 1. The OGSM provides to the NGTDM beginning-of-year reserves and production-to-reserves ratio for use in the short-term domestic nonassociated gas production functions that reside in the NGTDM, associated-dissolved natural gas production, and pipeline imports from Mexico. The interaction of supply and demand in NGTDM determines nonassociated gas production. The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

Figure 1. OGSM Interface with Other Oil and Gas Modules
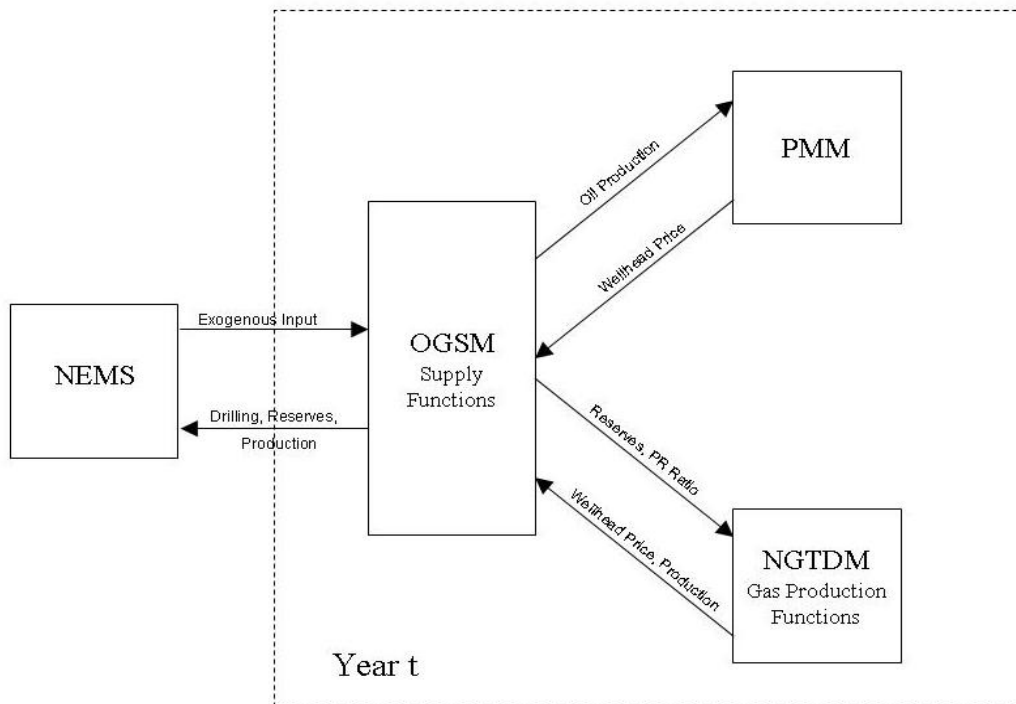
OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 2). The primary fuel types are crude oil and natural gas, 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 conventional and unconventional types. The unconventional gas category in OGSM consists of resources in tight sands, gas shales, and coalbed methane formations.

OGSM provides mid-term (through year 2030) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables including:

- drilling costs, production costs,

- regulatory or legislatively mandated environmental costs,

- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits, and

- the rate of penetration for different technologies into the industry by fuel type.

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

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

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

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

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

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

Figure 2. Oil and Gas Supply Regions

West Coast - 6

Rocky Mountain - 5

Pacific - 8

Northeast - 1

Midcontinent - 3

Atlantic - 7

Southwest - 4

Gulf Coast - 2

Shallow Gulf of Mexico - 9

Deep Gulf of Mexico - 10

Offshore North Slope

Onshore North Slope

Other Alaska
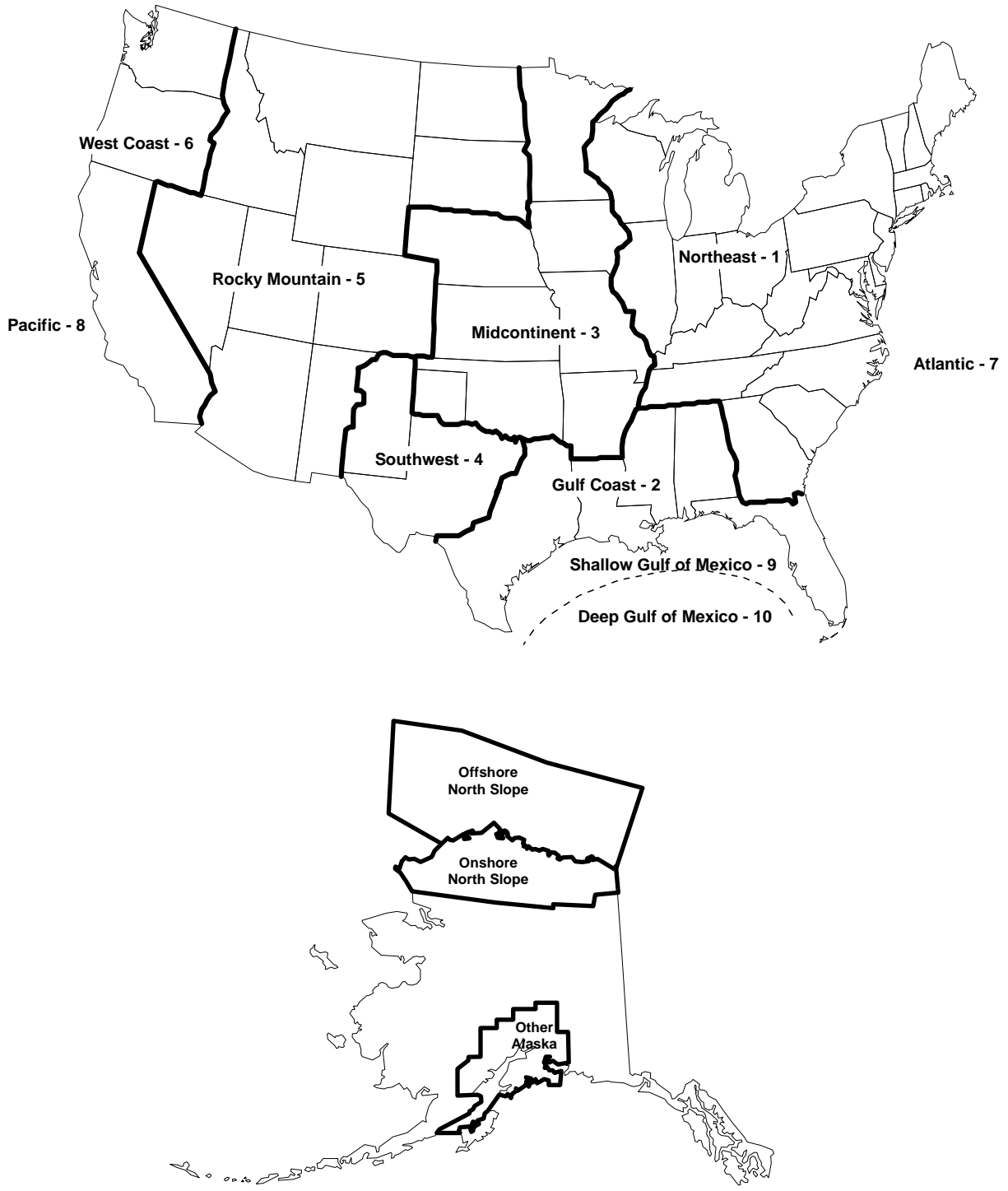
3. Model Structure

Introduction

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

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States, or acquire natural gas from foreign producers for resale in the United States, or sell U.S. gas to foreign consumers. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery (UGR) from low permeability sandstone and shale formations, and coalbeds. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents foreign trade in natural gas as pipeline imports and exports by entry region of the United States. Liquefied natural gas (LNG) imports are determined in the NGTDM.

Figure 3. Submodules within the Oil and Gas Supply Module
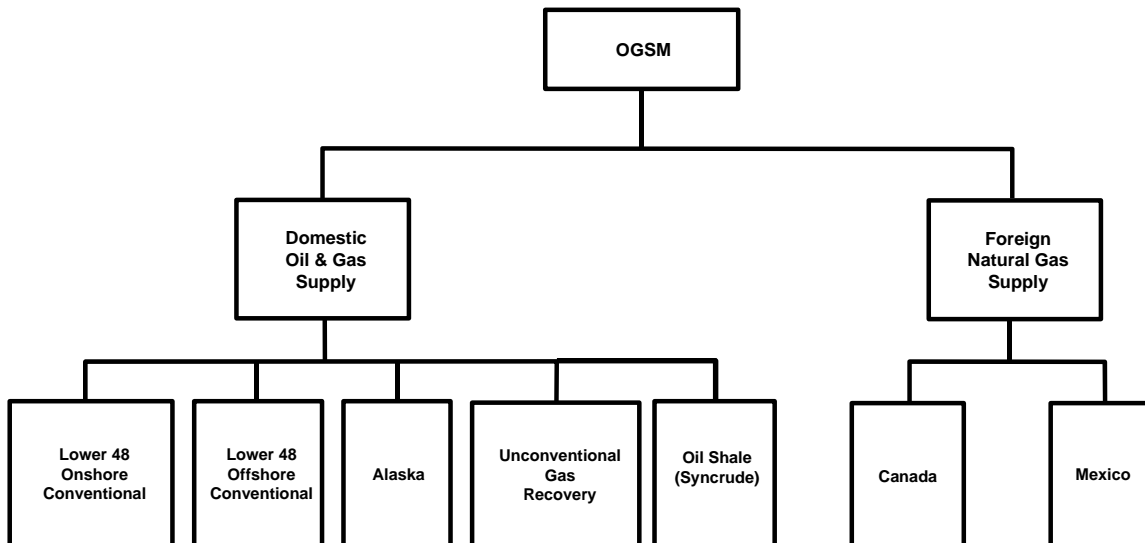
The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. In particular, the model assumes that investment in exploration and development drilling, by fuel type and geographic region, is a function of the expected profitability of exploration and development drilling, disaggregated by fuel type and geographic region.

Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM, compared to the previous EIA midterm model, incorporates a more complete and representative description of the processes by which oil and gas in the technically recoverable resource base[1] convert to proved reserves.[2]

The OGSM distinguishes between drilling for new fields (new field wildcats) and that for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions. This improved resource accounting approach is more consistent with the literature regarding resource recovery.[5]

The breadth of supply processes that are encompassed within OGSM results in different methodological approaches for determining crude oil and natural gas production from lower 48 onshore conventional resources, lower 48 onshore unconventional resources, lower 48 offshore, Alaska, and foreign gas trade. The present OGSM consequently comprises five submodules. The label OGSM as used in this report generally refers to the overall framework and the implementation of lower 48 onshore oil and conventional gas supply. The Unconventional Gas Recovery Supply Submodule (UGRSS) models gas supply from low permeability sandstone shale formations, and coalbeds. The Offshore Oil and Gas Supply Submodule (OOGSS) represents oil and gas exploration and development in the offshore Gulf of Mexico and Pacific regions. The Alaska Oil and Gas Supply Submodule (AOGSS) represents industry supply activity in Alaska. The Foreign Natural Gas Supply Submodule (FNGSS) models trade in natural gas between the United States and other countries. These distinctions are reflected in the presentation of the methodology in this chapter.

The following sections describe OGSM grouped into five conceptually distinct divisions. The first section describes crude oil and conventional gas supply in the lower 48 States. This is followed by the methodology of the Unconventional Gas Recovery Supply Submodule, the Offshore Oil and Gas Supply Submodule, and then the Alaska Oil and Gas Supply Submodule. The chapter concludes with the presentation of the Foreign Natural Gas Supply Submodule. A set of four appendices are included following the chapter. These separate reports provide additional detail on special topics relevant to the methodology. The appendices present extended discussions on the discounted cash flow (DCF)

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

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

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

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

[5]See, for example, *An Assessment of the Natural Gas Resource Base of the United States*, R.J. Finley and W.L. Fisher, *et al*, 1988, and *The Potential for Natural Gas in the United States*, Volume II, National Petroleum Council, 1992.

calculation, unconventional gas recovery, technologies for unconventional gas recovery, offshore oil and gas supply, and shale oil synthetic crude (syncrude) supply.

Lower 48 Onshore Supply Submodule

Introduction

This section describes the structure of the models that comprise the lower 48 onshore (excluding UGR) submodule of the Oil and Gas Supply Module (OGSM). The general outline of the lower 48 submodule of the OGSM is provided in Figure 4. The overall structure of the submodule can be best described as recursive. The structure implicitly assumes a sequential decision making process. A general description of the submodule's principal features and relationships computations is provided first. This is followed by a detailed discussion of the key mathematical formulas and computations used in the solution algorithm.

A discounted cash flow (DCF) algorithm is used to calculate the expected profitability of a representative well in each region. Inputs to this algorithm include oil and gas prices (from the PMM and NGTDM), production profiles, co-product ratios, drilling costs, lease equipment costs, operating costs, severance tax rates, ad valorem tax rates, royalty rates, State tax rates, Federal tax rates, tax credits, depreciation schedules, and success rates. Expected DCF values are calculated for each well type (exploratory, developmental), and for each fuel type (crude oil, shallow gas, and deep gas).

Exploratory and development wells by fuel type and region are predicted as functions of the expected profitability of the fuel and region-specific drilling activity. Based on region-specific historical patterns, exploration wells are broken down into new field wildcats and other exploratory wells.

The forecasted numbers of new field wildcats, other exploratory wells, and developmental wells are used in a set of finding rate equations to determine additions to oil and gas reserves each period. New field wildcats determine new field discoveries. Based on the historical relationship between the initial quantity of proved reserves discovered in a field and the field's ultimate recovery, reserves from new field discoveries are categorized into additions to proved reserves and inferred reserves. Inferred reserves are converted into proved reserves (extensions and revisions) in later periods by drilling other exploratory wells and development wells.

Reserve additions are added to the end-of-year reserves for the previous period while the current period's production is subtracted to yield the end of year reserves for the current period. Natural gas reserves along with an estimate of the expected production-to-reserves ratio for the next period are passed to the NGTDM for use in the short-run natural gas supply functions.

Figure 4. Flowchart for Lower 48 States Onshore Oil and Gas Submodule
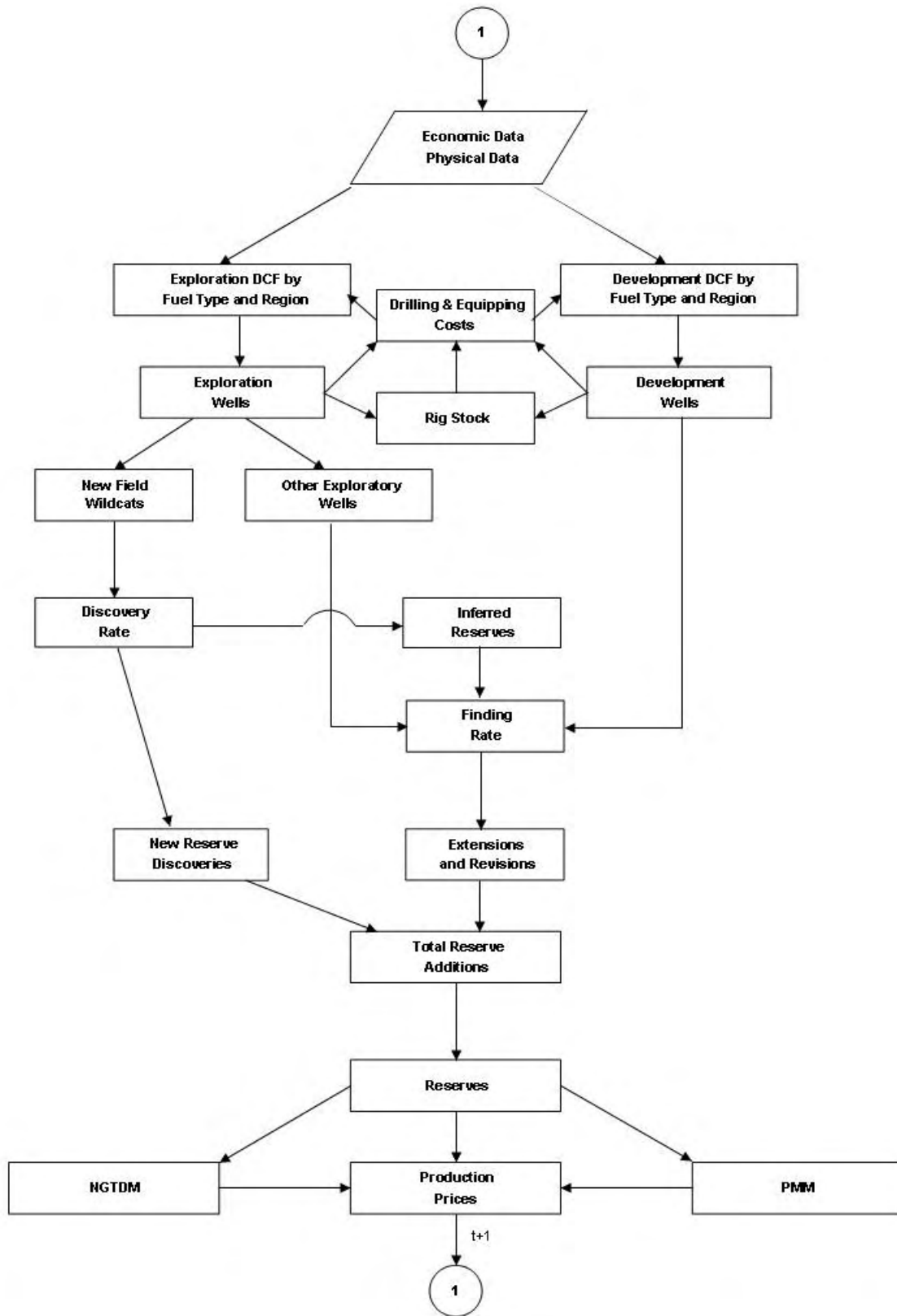
The Expected Discounted Cash Flow Algorithm

For each year t, the algorithm calculates the expected DCF for a representative well of type i, in region r, for fuel type k. The calculation assumes only one source of uncertainty--geology. The well can be a success (wet) or a failure (dry). The probability of success is given by the success rate (SR); the probability of failure is given by one minus the success rate (1-SR). For expediency, the model first calculates the discounted cash flow for a representative project, conditional on a requisite number of successful wells. The conditional project discounted cash flow is then converted into the expected discounted cash flow of a representative well as shown below.

Onshore Lower 48 Development

A representative onshore developmental project consists of one successful developmental well along with the associated number of dry holes. The number of dry developmental wells associated with one successful development well is given by [(1/SR) - 1] where SR represents the success rate for a development well in a particular region r and of a specific fuel type. Therefore, (1/SR) represents the total number of wells associated with one successful developmental well. All wells are assumed to be drilled in the current year with production from the successful well assumed to commence in the current year.

For each year of the project's expected lifetime, the net cash flow is calculated as:

$$
\begin{aligned}
\text{NCFON}_{i,r,k,s} = & \left(\text{REV} - (\text{ROY} + \text{PRODTAX} + \text{STATETAX} + \text{FEDTAX}) \right)_{i,r,k,s} \\
& - \left(\text{DRILLCOST} + \text{EQUIPCOST} + \text{OPCOST} + \text{DRYCOST} \right)_{i,r,k,s}
\end{aligned}
\tag{1}
$$

where,

NCFON	=	annual undiscounted net cash flow for a representative onshore development project
REV	=	revenue from the sale of the primary and co-product fuel
ROY	=	royalty taxes
PRODTAX	=	production taxes (severance plus ad valorem)
DRILLCOST	=	the cost of drilling the successful developmental well
EQUIPCOST	=	lease equipment costs
OPCOST	=	operating costs
DRYCOST	=	cost of drilling the dry developmental wells
STATETAX	=	state income tax liability
FEDTAX	=	federal income tax liability
i	=	well type (1 = exploratory, 2 = development)
r	=	subscript indicating onshore regions (see Figure 2 for OGSM region codes)
k	=	subscript indicating fuel type
s	=	subscript indicating year of project life.[6]

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[6]Abandonment of a project is expected to occur in that year of its life when the expected net revenue is less than expected operating costs. When abandonment does occur, expected abandonment costs are added to the calculation of the project's discounted cash flow.

The calculation of REV depends on expected production and prices. Expected production is calculated on the basis of individual wells. Flow from each successful well begins at a level equal to the historical average for production over the first 12 months. Production subsequently declines at a rate equal to the historical average production to reserves ratio. The default price expectation is that real prices will remain constant over the project's expected lifetime. The OGSM also can utilize an expected price vector provided from the NEMS system that reflects a user-specified assumption regarding price expectations. The calculations of STATETAX and FEDTAX account for the tax treatment of tangible and intangible drilling expenses, lease equipment expenses, operating expenses, and dry hole expenses. The algorithm also incorporates the impact of unconventional fuel tax credits and has the capability of handling other forms of investment tax credits. For a detailed discussion of the discounted cash flow methodology, the reader is referred to Appendix 3-A at the end of this chapter.

The undiscounted net cash flows for each year of the project, calculated by Equation (1), are discounted and summed to yield the discounted cash flow for the representative onshore developmental project (PROJDCFON). This can be written as:

$$PROJDCFON_{i,r,k,t} = SUCDCFON_{i,r,k,t} + \left[\frac{1}{SR_{i,r,k}} - 1 \right] * DRYDCFON_{i,r,k,t} \qquad (2)$$

where,

PROJDCFON	=	the discounted cash flow for a representative developmental project
SUCDCFON	=	the discounted cash flow associated with one successful onshore developmental well
DRYDCFON	=	the discounted cash flow associated with one dry onshore developmental well (dry hole costs).

Since the expected discounted cash flow for a representative onshore developmental well is equal to:

$$DCFON_{i,r,k,t} = SR_{i,r,k} * SUCDCFON_{i,r,k,t} + (1 - SR_{i,r,k}) * DRYDCFON_{i,r,k,t} \qquad (3)$$

it is easily calculated as:

$$DCFON_{i,r,k,t} = PRJDCFON_{i,r,k,t} * SR_{i,r,k} \qquad (4)$$

where,

DCFON	=	expected discounted cash flow for a representative onshore developmental well.
SR	=	drilling success rate

Onshore Lower 48 Exploration

A representative onshore exploration project consists of one successful exploratory well, $[(1/SR_{1,r,k})-1]$ dry exploratory wells, m_k successful development wells, and $m_k*[(1/SR_{2,r,k})-1]$ dry development wells. All exploratory wells are assumed to be drilled in the current year with production from the successful exploratory well assumed to commence in the current year. The developmental wells are assumed to be drilled in the second year of the project with production from the successful developmental well assumed to begin in the second year.

The calculations of the yearly net cash flows and the discounted cash flow for the exploratory project are identical to those described for the developmental project. The discounted cash flow for the exploratory project can be decomposed as:

$$PROJDCFON_{1,r,k,t} = SUCDCFON_{1,r,k,t} + \left(\frac{1}{SR_{1,r,k}} - 1 \right) * DRYDCFON_{1,r,k,t}$$

$$+ m_k * \left[SUCDCFON_{2,r,k,t} + \left(\frac{1}{SR_{2,r,k}} - 1 \right) * DRYDCFON_{2,r,k,t} \right]$$

(5)

where,

m_k = number of successful developmental wells in a representative project.

The first term on the right hand side represent the discounted cash flows associated with the successful exploratory well drilled in the first year of the project. The second term represents the impact of the dry exploratory wells drilled in the first year of the project. The third term represents the successful and dry developmental wells drilled in the second year of the project.

Again, as in the development case, the expected DCF for a representative onshore exploratory well is calculated by:

$$DCFON_{1,r,k,t} = PRJDCFON_{1,r,k,t} * SR_{1,r,k}$$

(6)

Calculation of Alternative Expected DCF's as Proxies for Expected Profitability

In some instances, the forecasting equations employ alternative, usually more aggregated, forms of the expected DCF. For example, an aggregate expected fuel level DCF is calculated for each region. This aggregate expected DCF is calculated as a weighted average of the expected exploratory DCF and the expected developmental DCF for each fuel. Specifically,

$$w1_{i,r,k,t} = \frac{WELLS_{i,r,k,t-1}}{\sum_{i=1}^{2} WELLS_{i,r,k,t-1}}$$

(7)

and

$$ODC\,FON_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * DCFON_{i,r,k,t}, \text{ for } k = 1$$

(8)

$$SGDC\,FON_{r,t} = \sum_{i=1}^{2} w1_{i,r,k,t} * DCFON_{i,r,k,t}, \text{ for } k = 3$$

(9)

where,

WELLS	=	wells drilled
ODCFON	=	expected DCF for oil
SGDCFON	=	expected DCF for shallow gas
DCFON	=	expected discounted cash flow for a representative onshore well.

Calculation of Exploration and Development Budget for Wells Determination

Expected U.S. budget for exploration and development is estimated as,

$$US\_ED_t = b0 * ROI\_FOREIGN_t^{b1} * RPCGAS_t^{b2} * RPCOIL_t^{b3} * PRDGAS_t^{b4} \tag{10}$$

where RPCGAS (RPCOIL) is the ratio of the price of natural gas (crude oil) in 1997 dollars to the national natural gas (crude oil) well operating cost index in 1997 dollars and PRDGAS is U.S. natural gas production.

The national operating cost indices were constructed as follows. For each year, a weighted average of regional well operating costs (in 1997 dollars) was calculated for oil, shallow gas, and deep gas using successful wells from the previous year as weights. The national gas operating cost was calculated as a weighted average of the national shallow and deep operating costs using successful wells from the previous year as weights. The indices were then calculated by dividing the operating costs for each year by the operating cost for 1997.

Lower 48 Onshore Wells Forecasting Equations

For each onshore Lower 48 region, the number of wells drilled by well class and fuel type is forecasted generally as a function of the expected profitability, proxied by the expected DCF, of a representative well of class i, in region r, for fuel type k, in year t and expected industry cash flow. In some specific cases, however, the forecasting equations may use the lagged value of the expected DCF or a more aggregate form of the expected DCF. The specific forms of the equations used in forecasting wells are given in Appendix D. These equations can be expressed in the following generalized form.

$$WELLSON_{i,r,k,t} = e^{m0_{i,r,k} + m1_{i,k} * DCFON_{i,r,k,t} * US\_ED_t} * REMAINRES_{r,k,t}^{m2_{i,k}} * WELLSON_{i,r,k,t-1}^{\rho_{i,k}}$$
$$* e^{-\rho_{i,k} * (m0_{i,r,k} + m1_{i,k} * DCFON_{i,r,k,t-1} * US\_ED_{t-1})} * REMAINRES_{r,k,t-1}^{-\rho_{i,k} * m2_{i,k}} \tag{11}$$

where,

WELLSON	=	lower 48 onshore wells drilled by class, region, and fuel type
DCFON	=	expected DCF for a representative onshore well of class i, in region r, for fuel type k, in year t
US_ED	=	U.S. budget for exploration and development in year t
REMAINRES	=	remaining unproved resources
m's	=	estimated parameters
ρ	=	estimated serial correlation parameter
i	=	well type
r	=	lower 48 regions
k	=	fuel type
t	=	year.

Successful and Dry Wells Determination

The number of successful wells in each category is determined by multiplying the forecasted number of total wells drilled in the category by the corresponding success rates. Specifically,

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k} \tag{12}$$

where,

SUCWELSON	=	successful onshore lower 48 wells drilled
WELLSON	=	onshore lower 48 wells drilled
SR	=	drilling success rate
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 onshore regions
k	=	fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas)
t	=	year.

Dry wells by class, region, and fuel type are calculated by:

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t} \tag{13}$$

where,

DRYWELON	=	number of dry wells drilled onshore
SUCWELSON	=	successful lower 48 onshore wells drilled by fuel type, region, and well type
WELLSON	=	onshore lower 48 wells drilled by fuel type, region, and well type
i	=	well type (1 = exploratory, 2 = development)
r	=	lower 48 onshore regions
k	=	fuel type (1 = shallow oil, 2 = deep oil, 3 = shallow gas, 4 = deep gas)
t	=	year.

Drilling, Lease Equipment, and Operating Cost Calculations

Three major costs classified within the OGSM are drilling costs, lease equipment costs, and operating costs (including production facilities and general/administrative costs). These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The successful drilling and dry hole cost equations capture the impacts of complying with environmental regulations, drilling to greater depths, rig availability, and technological progress.

One component of the drilling equations that causes costs to increase is the number of wells drilled in the given year. But within the framework of the OGSM, the number of wells drilled cannot be determined until the costs are known. Thus, drilling is estimated as a function of price as generalized below:

$$ESTOWELLS_t = \exp(b00) * POIL_t^{b1} * ESTOWELLS_{t-1}^{\rho} * \exp(-\rho * b00) * POIL_{t-1}^{-\rho * b1} \tag{14}$$

$$ESTGWELLS_t = \exp(b01) * PGAS_t^{b2} * ESTGWELLS_{t-1}^{\rho} * \exp(-\rho * b01) * PGAS_{t-1}^{-\rho * b2} \tag{15}$$

where,

ESTOWELLS	=	estimated total onshore lower 48 oil wells drilled
ESTGWELLS	=	estimated total onshore lower48 gas wells drilled
POIL	=	average wellhead price of crude oil
PGAS	=	average wellhead price of natural gas
b00, b01, b1, b2	=	estimated parameters
ρ	=	estimated serial correlation parameter
t	=	year.

The estimated level of drilling is then used to calculate the rig availability. The calculation is given by:

$$\text{RIGSL48}_t = e^{b0} * \text{RIGSL48}_{t-1}^{b1} * \text{REVRIG}_{t-1}^{b2} * \text{RIGSL48}_{t-1}^{\rho} * e^{-\rho*b0} * \text{RIGSL48}_{t-2}^{-\rho*b1} * \text{REVRIG}_{t-2}^{-\rho*b2} \quad (16)$$

where,

RIGSL48	=	onshore lower 48 rigs
REVRIG	=	total drilling expenditures per rig
b0, b1, b2	=	estimated parameters
ρ	=	estimated serial correlation parameter
t	=	year.

Drilling Costs

In each period of the forecast, the drilling cost per well is determined by:

$$\text{DRILLCOST}_{r,k,t} = e^{b0+b1_k*\text{DEPTH}_{r,k,t}} * \text{ESTWELLS}_t^{b2} * e^{b3*\text{TIME}_t} * e^{\text{CAPCOST}} * \text{DRILLCOST}_{r,k,t-1}^{\rho}$$
$$* e^{-\rho*(b0+b1_k*\text{DEPTH}_{r,k,t-1})} * \text{ESTWELLS}_{t-1}^{-\rho*b2} * e^{-\rho*b3*\text{TIME}_{t-1}} * e^{-\rho*CAPCOST} \quad (17)$$

$$\text{DRYCOST}_{r,k,t} = e^{b0+b1_k*\text{DEPTH}_{r,k,t}} * \text{ESTWELLS}_t^{b2} * e^{b3*\text{TIME}_t} * e^{\text{CAPCOST}} * \text{DRYCOST}_{r,k,t-1}^{\rho}$$
$$* e^{-\rho*(b0+b1_k*\text{DEPTH}_{r,k,t-1})} * \text{ESTWELLS}_{t-1}^{-\rho*b2} * e^{-\rho*b3*\text{TIME}_{t-1}} * e^{-\rho*CAPCOST} \quad (18)$$

where,

DRILLCOST	=	drilling cost per successful well
DRYCOST	=	drilling cost per dry hole
ESTWELLS	=	estimated total onshore lower 48 oil and gas wells drilled
RIGSL48	=	onshore lower 48 rigs
TIME	=	time trend - proxy for technology
CAPCOST	=	estimated capital cost escalation factor
r	=	OGSM lower 48 onshore region
k	=	fuel type (1 = shallow oil, 2 = deep oil, 3 = shallow gas, 4 = deep gas)
b0, b1, b2, b3, b4	=	estimated parameters
ρ	=	estimated serial correlation parameter
t	=	year.

Lease Equipment Costs

In each period of the forecast, lease equipment costs per successful well are determined by:

$$\text{LEQC}_{r,k,t} = e^{b0_{r,k}} * \text{DEPTH}_{r,k,t}^{b1_k} * \text{ESTSUCWELLS}_t^{b2_k} * e^{b3_k*\text{TIME}_t} * \text{LEQC}_{r,k,t-1}^{\rho_k}$$
$$* e^{-\rho_k*b0_{r,k}} * \text{DEPTH}_{r,k,t-1}^{-\rho_k*b1_k} * \text{ESTSUCWELLS}_{t-1}^{-\rho_k*b2_k} * e^{-\rho_k*b3_k*\text{TIME}_{t-1}} \quad (19)$$

where,

LEQC	=	oil and gas well lease equipment costs
DEPTH	=	average well depth
ESTSUCWELLS	=	estimated lower 48 successful onshore wells
TIME	=	time trend - proxy for technology
b0, b1, b2, b3	=	estimated parameters
ρ	=	estimated serial correlation parameter

r $\quad = \quad$ OGSM lower 48 onshore region

k $\quad = \quad$ fuel type (1=shallow oil, 2=deep oil, 3=shallow gas, 4=deep gas)

t $\quad = \quad$ year.

Operating Costs

In each period of the forecast, operating costs per successful well are determined by:

$$
\begin{aligned}
\text{OPC}_{\text{r,k,t}} = \ & e^{b0_{r,k}} * \text{DEPTH}_{\text{r,k,t}}^{b1_k} * \text{ESTSUCWELLS}_{\text{k,t}}^{b2_k} * e^{b3_k*\text{TIME}_t} * e^{b4_k*PGAS} * \text{OPC}_{\text{r,k,t}-1}^{\rho_k} \\
& * e^{-\rho_k*b0_{r,k}} * \text{DEPTH}_{\text{r,k,t-1}}^{-\rho_k*b1_k} * \text{ESTSUCWELLS}_{\text{k,t-1}}^{-\rho_k*b2_k} * e^{-\rho_k*b3_k*\text{TIME}_{t-1}} * e^{-\rho*b4_k*PGAS}
\end{aligned} \qquad (20)
$$

where,

$$
\begin{array}{rcl}
\text{OPC} & = & \text{oil and gas well operating costs} \\
\text{ESTSUCWELLS} & = & \text{estimated lower 48 successful onshore wells} \\
\text{DEPTH} & = & \text{average well depth} \\
\text{PGAS} & = & \text{regional average natural gas wellhead price (for oil only)} \\
\text{TIME} & = & \text{time trend - proxy for technology} \\
\text{b0, b1, b2, b3, b4} & = & \text{estimated parameters} \\
\rho & = & \text{estimated serial correlation parameter} \\
\text{r} & = & \text{OGSM lower 48 onshore region} \\
\text{k} & = & \text{fuel type (1=shallow oil, 2=deep oil, 3=shallow gas, 4=deep gas)} \\
\text{t} & = & \text{year.}
\end{array}
$$

The estimated wells, rigs, and cost equations are presented in their generalized form but the forecasting equations include a correction for first order serial correlation as shown in Appendix D.

Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to the stocks proved and inferred reserves. Reserve additions are calculated through a set of equations accounting for new field discoveries, discoveries in known fields, and incremental increases in volumetric recovery that arise during the development phase. There is a 'finding rate' equation for each phase in each region and for each fuel type.

Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. Proved reserves are reserves that can be certified using the original discovery wells, while inferred reserves are those hydrocarbons that require additional drilling before they are termed proved. Additional drilling takes the form of other exploratory drilling and development drilling. Other exploratory drilling account for proved reserves added through new pools or extensions. The determinants of revisions and adjustments are not well understood and thus projecting net revisions and adjustments is somewhat problematic, particularly for natural gas. For example, a negative adjustment or revision can be recorded because of a change in ownership and, thus, not linked directly to drilling. Over the last 25 years, net natural gas revisions and adjustments have varied from a low of -2.2 trillion cubic feet to as much as 3.1 trillion cubic feet.

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves. The proportions of reserves allocated to these categories are based on historical reserves growth statistics. Specifically, the allocation of reserves between proved and inferred reserves is based on the ratio of the initial reserves estimated for a newly discovered field relative to ultimate recovery from the

field.[7]

Functional Forms

Wells are divided into three categories: (1) new field wildcats, (2) other exploratory wells, and (3) development wells. For the rest of the chapter, successful new field wildcats will be designated by the variable SW1, other successful exploratory wells by SW2, and successful development wells by SW3.

New reserve discoveries per successful new field wildcat are a function of drilling activity, average depth, and the estimated volume of remaining undiscovered resources. Specifically, the finding rate equation for new field wildcats is:

$$FR1_{r,k,t} = e^{\beta 0_k} * RESOURCE_{r,k,t-1}^{\beta 1_{r,k}} * SW1_{r,k,t}^{\beta 2_k} * DEPTH_{r,k,t}^{\beta 3_k} \tag{21}$$

where,

$$
\begin{array}{rcl}
FR1 & = & \text{new field wildcats finding rate} \\
RESOURCE & = & \text{remaining undiscovered resources} \\
SW1 & = & \text{number of successful new field wildcats} \\
DEPTH & = & \text{average well depth} \\
\beta 0, \beta 1, \beta 2, \beta 3 & = & \text{estimated parameters} \\
r & = & \text{region} \\
k & = & \text{fuel type (oil or gas)} \\
t & = & \text{year.}
\end{array}
$$

The above equation provides a rate at which undiscovered resources convert into proved and inferred reserves as a function of cumulative new field wildcats. Given an estimate for the ratio of ultimate recovery from a field relative to the initial proved reserve estimate, $X_{r,k}$, the $X_{r,k}$ reserve growth factor is used to separate newly discovered resources into either proved or inferred reserves. Specifically, the change in proved reserves from new field discoveries for each period is given by

$$NRD_{r,k,t} = \frac{1}{X_k} * FR1_{r,k,t} * SW1_{r,k,t} \tag{22}$$

where,

$$
\begin{array}{rcl}
X & = & \text{reserves growth factor} \\
NRD & = & \text{additions to proved reserves from new field discoveries.}
\end{array}
$$

X is derived from historical data and it is assumed to be constant during the forecast period.

Reserves are converted from inferred to proved in a similar way as proved and inferred reserves are modeled as moving from the resource base as described above. The volumetric return to other exploratory wells is shown in the following equations.

$$
\begin{aligned}
FR2_{r,k,t} = & \; e^{\beta 0_{r,k}} * INFR_{r,k,t}^{\beta 1_{r,k}} * SW2_{r,k,t}^{\beta 2_k} * WHP_{r,k,t}^{\beta 3_{r,k}} * e^{\beta 4_k * year_t} * FR2_{r,k,t-1}^{\rho_k} \\
& * e^{-\rho_k * \beta 0_{r,k}} * INFR_{r,k,t-1}^{-\rho_k * \beta 1_{r,k}} * SW2_{r,k,t-1}^{-\rho_k * \beta 2_k} * WHP_{r,k,t-1}^{-\rho_k * \beta 3_{r,k}} * e^{-\rho_k * \beta 4_k * year_{t-1}}
\end{aligned} \tag{23}
$$

---

[7]A more complete discussion of the topic of reserve growth for producing fields can be found in Chapter 3 of *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy.*

where,

FR2	=	other exploratory well finding rate
INFR	=	remaining inferred reserves
SW2	=	successful other exploratory wells
WHP	=	wellhead price
$\beta 0, \beta 1, \beta 2, \beta 3, \beta 4$	=	estimated parameters
ρ	=	estimated serial correlation parameter
r	=	region
k	=	fuel type (oil or gas)
t	=	year.

The total volume of proved reserves added in any year through other exploratory drilling in the form of new pools and extensions is given by

$$EXTENSIONS_{r,k,t} = FR2_{r,k,t} * SW2_{r,k,t} \tag{24}$$

The final reserve category is revisions. As noted earlier, revisions can not be directly linked to developmental drilling. Revisions are set equal to the historical average over the last 14 years.

$$REVISIONS_{r,k,t} = \frac{\sum_{year=1990}^{2003} REVISIONS_{r,k,year}}{14} \tag{25}$$

Total reserve additions in period t are given by the following equation:

$$RA_{r,k,t} = NRD_{r,k,t} + EXTENSIONS_{r,k,t} + REVISIONS_{r,k,t} \tag{26}$$

Finally, total end of year proved reserves for each period equals:

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{27}$$

where,

R	=	reserves measured as of the end-of-year
Q	=	production.

Production to Reserves Ratio

The production of nonassociated gas in NEMS is modeled at the "interface" of NGTDM and OGSM while oil production[8] is determined within the OGSM. In both cases, the determinants of production include the lagged production to reserves (PR) ratio and price. The PR ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

For each year t, the PR ratio is calculated as:

---

[8]Electricity cogeneration and capacity associated with production from enhance oil recovery techniques is held constant at an average historical level.

$$PR_{r,k,t} = \frac{Q_{r,k,t}}{R_{r,k,t-1}}$$

(28)

where,

PR_t = production to reserves ratio for year t

Q_t = production in year t (received from the NGTDM and the PMM)

R_{t-1} = end of year reserves for year (t-1) or equivalently, beginning of year reserves for year t.

$PR_{r,k,t}$ represents the rate of extraction from all wells drilled up to year t (through year t-1). Because the production to reserves ratio is between zero and one, there is merit to estimating the logistical transformation of the PR ratio rather than estimate the ratio itself. In this case the dependent variable is $LOGISTIC_{r,k,t}$ which is defined as

$$LOGISTIC_{r,k,t} = \ln\left(\frac{PR_{r,k,t}}{1 - PR_{r,k,t}}\right)$$

(29)

The variable LOGISTIC is estimated using the calculation

$$
\begin{aligned}
LOGISTIC_{r,k,t} = a_{r,k} * (1 - \rho_k) &+ b0 * \frac{REVISIONS_{r,k,t}}{SW3_{r,k,t}} + b1 * \frac{NRD_{r,k,t} + EXTENSIONS_{r,k,t}}{SW3_{r,k,t}} \\
&+ b2_{r,k} * \ln(SW3_{r,k,t}) + \rho_k * LOGISTIC_{r,k,t-1} \\
&- \rho_k * [b0 * \frac{REVISIONS_{r,k,t-1}}{SW3_{r,k,t-1}} + b1 * \frac{NRD_{r,k,t-1} + EXTENSIONS_{r,k,t-1}}{SW3_{r,k,t-1}} + b2_{r,k} * \ln(SW3_{r,k,t-1})]
\end{aligned}
$$

(30)

where RA_RATIO is the ratio of total reserve additions to beginning of year reserves in year t. The PR ratio is then determined by

$$PR_{r,k,t} = \frac{\exp(LOGISTIC_{r,k,t})}{1 + \exp(LOGISTIC_{r,k,t})}$$

(31)

$PR_{r,k,t}$ is constrained not to vary from $PR_{r,k,t-1}$ by more than 10 percent. It is also constrained not to exceed 30 percent.

The values for $R_{r,k,t}$ and $PR_{r,k,t+1}$ for natural gas are passed to the NGTDM for use in their market equilibration algorithms and for crude oil are passed to a subroutine in OGSM, both of which solve for equilibrium production and prices for year (t+1) of the forecast using the following short-term supply function:

$$Q_{r,k,t+1} = R_{r,k,t} * PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})$$

(32)

where,

R_t = end of year reserves in period t

PR_t = extraction rate in period t

β = estimated short run price elasticity of supply

ΔP_{t+1} = $(P_{t+1}-P_t)/P_t$, proportional change in price from t to t+1.

The P/R ratio for period t, PR_t, is assumed to be the approximate extraction rate for period t+1 under normal operating conditions. The product $(R_{r,k,t} * PR_t)$ is the expected, or normal, operating level of

production for period t+1. Actual production in t+1 will deviate from expected depending on the proportionate change in price from period t and on the value of short run price elasticity. Documentation of the equations used to estimate β is provided in Appendix D.

Associated-dissolved Gas

The production of associated-dissolved gas (AD gas) was assumed to be a function of end-of-year reserves and AD gas production for the previous year and oil production in the current year. The P/R ratio for AD gas is then calculated as the ratio of AD gas production in the current year to the end-of-year reserves in the previous year.

$$Q\_ADGAS_{r,t} = e^{\alpha 0} * Q\_ADGAS_{r,t-1}^{\alpha 1} * R\_ADGAS_{r,t-1}^{\alpha 2} * OILPRD_{r,t}^{\alpha 3} \qquad (33)$$

where,

Q_ADGAS	=	associated-dissolved gas production
R_ADGAS	=	associated-dissolved gas reserves measured as of the end-of-year
OILPRD	=	crude oil production
r	=	OGSM region
t	=	year
α0, α1, α2, α3	=	estimated parameters

The PR ratio is then determined by

$$PR\_ADGAS_{r,t} = \frac{Q\_ADGAS_{r,t}}{R\_ADGAS_{r,t-1}} \qquad (34)$$

Associated-dissolved gas reserve additions are given by

$$RA\_ADGAS_{r,t} = \beta 0 + \beta 1 * NRD_{r,t} + \beta 2 * EXTENSIONS_{r,t} + \beta 3 * REVISIONS_{r,t} \qquad (35)$$

Finally, end-of-year associated-dissolved gas reserves equals:

$$R\_ADGAS_{r,t} = R\_ADGAS_{r,t-1} - Q\_ADGAS_{r,t} + RA\_ADGAS_{r,t} \qquad (36)$$

Unconventional Gas Recovery Supply Submodule

This section describes the basic structure of the Unconventional Gas Recovery Supply Submodule (UGRSS). The UGRSS is designed to project gas production from unconventional gas deposits. This section provides an overview of the basic modeling approach. A more detailed description of the methodology is presented in Appendix 3-B and an in depth view of the treatment of technology in the UGRSS is provided in Appendix 3-C.

The UGRSS is a play level model that specifically analyzes the three major unconventional resources - coalbed methane, tight gas sands, and gas shales. The UGRSS calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play. Subsequently, prices received from the NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EUR's for the wells in that play. Other drilling is "infill" in nature and does not result in reserve additions. This latter drilling is based on projected production for the year and is essentially the additional wells required to meet that production level. Given the projected reserve additions, reserve levels and (Aexpected") production-to-reserves (P/R) ratios are recalculated at the NGTDM region level. The resultant values are sent to OGSM, where they are aggregated with similar values from the other submodules. The aggregate P/R ratios and reserve levels are then passed to the NGTDM, which determines through market equilibration the prices and production for the following year.

Offshore Supply Submodule

This section describes the basic structure of the Offshore Oil and Gas Supply Submodule (OOGSS). The OOGSS is designed to project the exploration and development of U.S. offshore oil and natural gas resources. As described in previous sections, annual production is not determined within the OOGSS but rather the parameters for the short-term supply functions that are used in the market equilibration routine within the NGTDM and PMM. This section provides an overview of the basic approach. A more detailed description of the methodology is presented in Appendix 3-D as well as a discussion of the characterization of the undiscovered resource base and the various technology options for offshore exploration, development, and production practices incorporated in the OOGSS.

The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories: (1) undiscovered fields, (2) discovered, undeveloped fields, and (3) producing fields. 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 five water depth categories: 0-200 meters, 200-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for four offshore regions: Pacific, Atlantic, shallow GOM (water depth less than 200 meters), and deep GOM (water depth greater than 200 meters).

Crude oil production includes oil condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Alaska Oil and Gas Supply Submodule

This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil and gas production from the Onshore North Slope, Offshore North Slope, and Other Alaska (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Alaskan National Wildlife Refuge area in the east. This section provides an overview of the basic approach including a discussion of the discounted cash flow (DCF) method.

AOGSS Overview

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 5).Transportation costs are used in conjunction with the relevant market price of oil or natural gas to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow (DCF) method is used to determine the economic viability of Alaskan drilling and production activities. Oil and gas investments decisions are modeled on the basis of discrete projects, in contrast to the Onshore Lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field is dependent on s profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, and historical production patterns and announced plans for currently producing fields.

Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as:

- Drilling costs,

- Lease equipment costs, and

- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms relative to

Figure 5. Flowchart of the Alaska Oil and Gas Supply Submodule

For each period t:

```
                              ┌─────────────────────────────┐
                              │   Economic & Physical Data  │
                              └─────────────────────────────┘
                                            │
                              ┌─────────────────────────────┐
                              │  Estimate transportation costs │
                              └─────────────────────────────┘
                                            │
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
NEW FIELDS
                              ┌─────────────────────────────┐
                              │ Determine DCF for next discovery size │
                              └─────────────────────────────┘
                                            │
                                         ◇ DCF > 0 ◇ ──── False ────┐
                                            │ True                  │
               ┌───────────────────────────────────────────────┐   │
               │ Determine outcome for allowable number of New Field Wildcats │
               │ Add any successes to inventory of development projects │
               │ Record                                         │   │
               │    - Drilling                                  │   │
               │    - Reserve additions                         │   │
               │    - Financial expenditures                    │   │
               └───────────────────────────────────────────────┘   │
                                            │                       │
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - │
DEVELOPMENT                                                         │
PROJECTS         ┌────────────────────────────────────────┐ ◄──────┘
              ┌─►│        Compute DCF for project          │◄──┐
              │  └────────────────────────────────────────┘   │
              │                 │                              │
              │              ◇ DCF > 0 ◇ ── False ──► ┌──────────────────┐
              │                 │ True                │ Suspend operation │
              │     ┌─────────────────────────┐       └──────────────────┘
              │     │ Continue project, record │
              │     │    - Drilling            │
              │     │    - Financial expenditures │
              │     └─────────────────────────┘
              │                 │
              │   False ◄──── ◇ Project complete ◇
              │                 │ True
              │     ┌─────────────────────────┐
              │     │ Add project to producing fields │
              │     └─────────────────────────┘
              │                 │
   ┌──────────────────┐  False  ◇ All projects evaluated ◇ ◄──
   │ Go to next project │◄──────                          
   └──────────────────┘              │ True
- - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
PRODUCING FIELDS
                    ┌─────────────────────────────────┐
                    │ For all fields, compute production (PROD) │
                    └─────────────────────────────────┘
                                     │
                                ◇ PROD>QMIN ◇ ── False ──┐
                                     │ True              │
                    ┌──────────────────┐      ┌──────────────────────┐
                    │ Record production │      │ Shut down, remove field │
                    └──────────────────┘      └──────────────────────┘
```

what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48, but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements that are included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation, and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$\mathrm{DRILLCOST}_{i,r,k,t} = \mathrm{DRILLCOST}_{i,r,k,T_b} * (1 - \mathrm{TECH}1) ** (t - T_b) \tag{37}$$

where,

$$
\begin{array}{rcl}
i & = & \text{well class (exploratory=1, developmental=2)} \\
r & = & \text{region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)} \\
k & = & \text{fuel type (oil=1, gas=2)} \\
t & = & \text{forecast year} \\
\mathrm{DRILLCOST} & = & \text{drilling costs} \\
T_b & = & \text{base year of the forecast} \\
\mathrm{TECH}1 & = & \text{annual decline in drilling costs due to improved technology.}
\end{array}
$$

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once this equipment is moved up to Alaska, it is too expensive to transport back to the lower 48. Consequently, company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of limited number of drilling rigs and equipment available for use.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil or gas well is given by:

$$\mathrm{EQUIP}_{r,k,t} = \mathrm{EQUIP}_{r,k,t} * (1 - \mathrm{TECH}2)^{r - T_b} \tag{38}$$

where,

$$
\begin{array}{rcl}
r & = & \text{region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)} \\
k & = & \text{fuel type (oil=1, gas=2)} \\
t & = & \text{forecast year} \\
\mathrm{EQUIP} & = & \text{lease equipment costs}
\end{array}
$$

$$T_b \quad = \quad \text{base year of the forecast}$$
$$\text{TECH2} \quad = \quad \text{annual decline in lease equipment costs due to improved technology.}$$

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$\text{OPCOST}_{r,k,t} = \text{OPCOST}_{r,k,t} * (1 - \text{TECH2})^{r - T_b} \tag{39}$$

where,

$$r \quad = \quad \text{region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)}$$
$$k \quad = \quad \text{fuel type (oil=1, gas=2)}$$
$$t \quad = \quad \text{forecast year}$$
$$\text{OPCOST} \quad = \quad \text{operating cost}$$
$$T_b \quad = \quad \text{base year of the forecast}$$
$$\text{TECH3} \quad = \quad \text{annual decline in operating costs due to improved technology.}$$

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil and gas producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.

- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.

- Operating costs are expensed.

- All remaining successful field development costs are capitalized.

- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil and gas projects.[9] A positive DCF is necessary to continue operations for a known field, whether exploration, development, or production. Selection of new prospects for initial exploration occurs on the basis of the profitability index which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the transportation cost to lower 48 markets. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs, while natural gas transportation costs are strictly pipeline costs (tariffs) to the lower 48. Transportation costs are specified for each field, based on the fuel type (i.e., oil or gas) and on the transportation cost of that fuel for that region. This cost directly affects the expected revenues from the production of a field as follows:[10]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \tag{40}$$

where,

$$
\begin{aligned}
f &= \text{field} \\
t &= \text{year} \\
REV &= \text{expected revenues} \\
Q &= \text{expected production volumes} \\
MP &= \text{market price in the lower 48 states} \\
TRANS &= \text{transportation cost.}
\end{aligned}
$$

The expected discounted cash flow associated with a representative oil or gas project in a field f at time t is given by:

$$
\begin{aligned}
DCF_{f,t} = (&PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\
&- PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t}
\end{aligned} \tag{41}
$$

where,

$$
\begin{aligned}
PVREV &= \text{present value of expected revenues} \\
PVROY &= \text{present value of expected royalty payments} \\
PVDRILLCOST &= \text{present value of all exploratory and developmental drilling expenditures} \\
PVEQUIP &= \text{present value of expected lease equipment costs} \\
TRANSCAP &= \text{cost of incremental transportation capacity} \\
PVOPCOST &= \text{present value of operating costs} \\
PVPRODTAX &= \text{present value of expected production taxes (ad valorem and severance taxes)} \\
PVSIT &= \text{present value of expected state corporate income taxes} \\
PVFIT &= \text{present value of expected federal corporate income taxes}
\end{aligned}
$$

---

[9]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[10]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

$$\text{PVWPT} \quad = \quad \text{present value of expected windfall profits tax}[11]$$

The expected capital costs for the proposed field f located in region r are:

$$\text{COST}_{f,t} = (\text{PVEXPCOST} + \text{PVDEVCOST} + \text{PVEQUIP} + \text{TRANSCAP})_{f,t} \tag{42}$$

where,

$$
\begin{array}{lll}
\text{PVEXPCOST} & = & \text{present value exploratory drilling costs} \\
\text{PVDEVCOST} & = & \text{present value developmental drilling costs} \\
\text{PVEQUIP} & = & \text{present value lease equipment costs} \\
\text{TRANSCAP} & = & \text{cost of incremental transportation capacity}
\end{array}
$$

The profitability indicator from developing the proposed field is therefore equal to:

$$\text{PROF}_{f,t} = \frac{\text{DCF}_{f,t}}{\text{COST}_{f,t}} \tag{43}$$

The field with the highest positive PROF in time t is then eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into reserves requires a successful new field wildcat well. The discovery procedure can be determined endogenously or supplied at the option of the user. The procedure requires data regarding:

- the maximum number of new field wildcat wells drilled in any year,

- new field wildcat success rate, and

- any restrictions on the timing of drilling.

- technically recoverable oil and gas resource estimates by region,

- distribution of technically recoverable field sizes within each region,

The endogenous procedure generates:

- the set of individual fields to be discovered, specified with respect to size and location,

- an order for the discovery sequence, and

- a schedule for the discovery sequence.

---

[11]Since the Windfall Profits Tax was repealed in 1988, this variable would normally be set to zero. It is included in the DCF calculation for completeness.

The new field discovery procedure divides the estimate for technically recoverable oil and gas resources into a set of individual fields. The field size distribution data is obtained from U.S. Geological Survey estimates.[12] The field size distribution is used to determine a largest field size based on the volumetric estimate corresponding to an acceptable percentile of the distribution. The remaining fields within the set are specified such that the distribution of estimated sizes conforms to the characteristics of the input distribution. Thus, this estimated set of fields is consistent with the expected geology with respect to expected aggregate recovery and the relative frequency of field sizes.

New field wildcat drilling depends on the estimated expected DCF for the set of remaining undiscovered recoverable prospects. If the DCF for each prospect is not positive, no new drilling occurs. Positive DCF's motivate additional new field wildcat drilling. Drilling in each year matches the maximum number of new field wildcats. A discovery occurs as indicated by the success rate; i.e., a success rate of 12.5 percent means that there is one discovery in each sequence of eight wells drilled. By assumption, the first new field well in each sequence is a success. The requisite number of dry holes must be drilled prior to the next successful discovery.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules would also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in Alaskan National Wildlife Refuge were permitted, then the earliest possible development date would be 2011. Another example is the development of the West Sak field is expected to be delayed until technology can be developed that will enable the heavy crude oil of that field to be economically extracted.

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the drilling schedule is determined by the user or some set of specified rules. However, if the DCF for a given project is negative, then exploration and development of this project is suspended in the year in which this occurs. The DCF for each project is evaluated in subsequent years for a positive value; at which time, exploration and development will resume.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[13] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to peak rate,

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[12]*Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, USGS (1989); and *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*, USGS (April 2001); and *U.S. Geological Survey 2002 Petroleum Resource Assessment of the National Petroleum Reserve in Alaska (NPRA)* USGS (2002).

[13]*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).

- peak rate sustained for 3 to 8 years, and

- production rates decline by 5 to 18 percent per year, for known fields under development, after production declines below the peak rate; unknown fields decline by 10 percent per year.

The 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 (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for any given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been explored, but that have not begun production. These fields include, for example, a series of expansion fields in the Prudhoe Bay area, and a series of fields in the National Petroleum Reserve, Alaska (NPRA). For these fields, the starting date of production was not determined by the discovery process outlined above, but is based upon estimates of when these fields will come into production, from both the state of Alaska and EIA. (*2000 Annual Report,* Alaska Department of Natural Resources, Division of Oil and Gas, 2000, and *Future Oil Production for the Alaska North Slope*, EIA, Office of Oil and Gas, DOE/EIA-0627, May 2001.)

Producing Fields

Oil and natural gas production from fields producing as of the base year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. Production ceases when flow becomes subeconomic; i.e., attains the assumed minimum economic production level.

The percent of oil in-place recovered from a North Slope producing field is determined by prevailing world oil prices. The North Slope oil fields produce predominantly low to medium gravity oils. The percent recovery of North Slope oil in-place depends upon the extent to which the petroleum companies drill and operate new infill water injectors and production wells to produce these low to middle quality oils. Higher oil prices increase the percent recovery of the oil in-place by encouraging North Slope oil producers to increase their infill drilling and to inject more water. Because Prudhoe Bay oil field is the largest and most typical middle gravity oil field on the North Slope, the impact of oil prices on the recovery of in-place resources for middle gravity oil fields was based on an expected recovery rate of 45 percent at $25 per barrel for Prudhoe Bay. At oil prices of $10 per barrel or below, the minimum recovery factor for the middle gravity oil in-place oil is 35 percent, which linearly increases to maximum recovery of 55 percent $40 per barrel and above. For the North Slope heavy oil fields (i.e., low gravity oil) 10 percent recovery of the in-place oil is expected at $25 per barrel. At $10 per barrel or less, the minimum recovery drops to 7.5 percent for a heavy oil field. At $40 per barrel or more, the maximum recovery increases to 12.5 percent for a heavy oil field.

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.[14] In addition, the re-injection of North Slope gas for increased oil recovery poses an operational/economic barrier limiting its early extraction. Nonetheless, there are no extraordinary regulations or legal constraints interfering with the recovery and use of this gas. Thus, the modeling of natural gas production for marketing in the lower 48 states recognizes the expected

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[14]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.

delay to maximize oil recovery, but it does not require any further modifications from the basic procedure.[15]

Over the forecast period, Alaskan natural gas production is limited to natural gas resources in the Prudhoe Bay field and the adjacent Port Thompson field. In all, these fields have estimated reserves of 35 trillion cubic feet of natural gas.[16] Of this, EIA has estimated that 26 trillion cubic feet could be produced with only a minor impact on North Slope oil production. All Alaska North Slope natural gas production in the EIA forecast is limited to this 26 Tcf of stranded gas reserves. EIA estimates that this already discovered gas requires a return of at least $1.14 (2006 dollars per thousand cubic feet) at the wellhead in Alaska before these reserves would be developed.

Foreign Natural Gas Supply Submodule

This section describes the structure for the Foreign Natural Gas Supply Submodule (FNGSS) within the Oil and Gas Supply Module (OGSM). FNGSS includes U.S. trade in foreign natural gas via either the North American pipeline network or ocean-going tankers.[17] Gas is traded with Canada and Mexico via pipelines. The border crossing locations are identified in Figure 6. Gas trade with other, nonadjacent, countries is in the form of liquefied natural gas (LNG) and involves liquefaction, transportation by tanker and subsequent regasification.

Figure 6. Foreign Natural Gas Trade

---
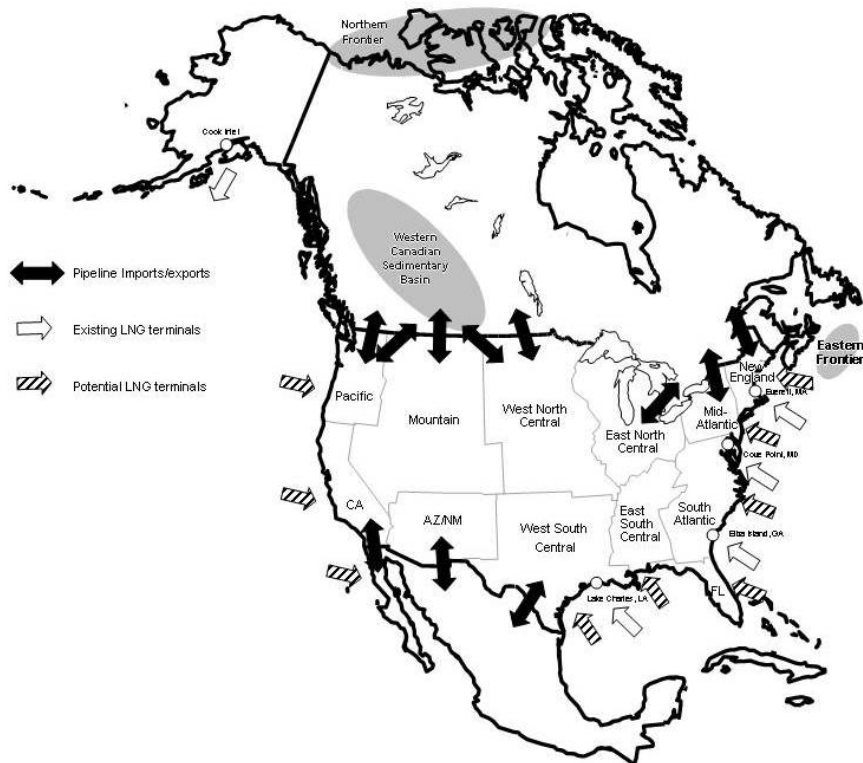
[15]The current version of AOGSS does not include r an explicit method to deal with the issue of marketing ANS gas as liquefied natural gas (LNG) exports to Pacific Rim countries. The working assumption is that sufficient recoverable gas resources are present to support the economic operation of both a marketing system to the Lower 48 States and the LNG export project, but that the netback from the Lower-48 States is likely higher than for LNG and therefore preferred.

[16]*Alaska Gas: Clean Energy for the Future*, British Petroleum, 2001.

[17]The issue of foreign gas trade generally is viewed as one of supply (to the United States) because the United States is currently a net importer of natural gas by a wide margin, a situation that is expected to continue.

A representation of Canadian gas reserves accounting and well development has been established. Since forecasts of fixed volumes are not adequate for the purposes of equilibrating supply and demand, this submodule provides the Natural Gas Transmission and Distribution Module (NGTDM) with a supply function of conventional Canadian natural gas at the western Canadian supply point. With the help of these supply parameters, Canadian imports to the United States are defined by the North American market equilibration that occurs in the NGTDM. Natural gas imports via pipeline from Mexico are handled with less detail. LNG imports are modeled on the basis of importation costs, including production, liquefaction, shipping, and regasification. Projected imports of LNG are subject to user assumptions regarding the timing and size of available import capacity. Natural gas LNG and Canadian exports are included in the National Energy Modeling System (NEMS) as exogenous assumptions. Exports to Mexico are determined endogenously. This section presents descriptions of the separate methodological approaches used to represent Canadian, Mexican, and LNG natural gas trade.

Canadian Gas Trade

This submodule determines the components and the subsequent parameters needed to define the Western Canadian conventional natural gas price/supply curve used by the NGTDM to help determine Canadian import levels. Canadian production is represented for three regions in the NEMS -- the Western Canadian Sedimentary Basin (WCSB, including Alberta, British Columbia, and Saskatchewan), the Northern Frontier (Arctic Islands and MacKenzie Delta), and Eastern Canada. Production from the WCSB is further disaggregated into conventional (including tight gas) and unconventional (coalbed methane) production. Eastern Canadian production is set exogenously in the NGTDM. Baseline production levels for unconventional (coalbed) production are effectively set exogenously in the NGTDM as well, but are allowed to vary in the NGTDM in response to variations in the realized price. Gas production from the MacKenzie Delta is dependent on the construction of a pipeline to Alberta, which is also determined by the NGTDM and documented separately. Finally, the NGTDM includes an algorithm for setting LNG imports into Canada.

The approach taken to determine WCSB gas supplies differs from that used in the domestic submodules of the OGSM. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of the Western Canadian natural gas wellhead price, remaining resources, and production-to-reserve ratio, rather than as a function of expected profitability proxied by the expected DCF. No distinction is made between exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves); and an estimated extraction rate determines production potential [production to reserves ratio (PRR)].   The general methodology employed for estimating potential conventional (including tight gas) Canadian gas production from the WCSB is depicted in Figure 7. Production from unconventional sources (i.e., coalbed methane, largely in Western Canada) is handled within the NGTDM as an assumed production function dependent on price.

The determination of the import volumes into the United States occurs in the equilibration process of the NGTDM, utilizing the WCSB supply curve parameters, unconventional and eastern Canadian production, gas from the MacKenzie Delta, as well as Canadian demand estimates. Forecasts of Canadian consumption are set at levels published in EIA's *International Energy Outlook 2007*.

Figure 7. General Outline of the Canadian Algorithm of the FNGSS
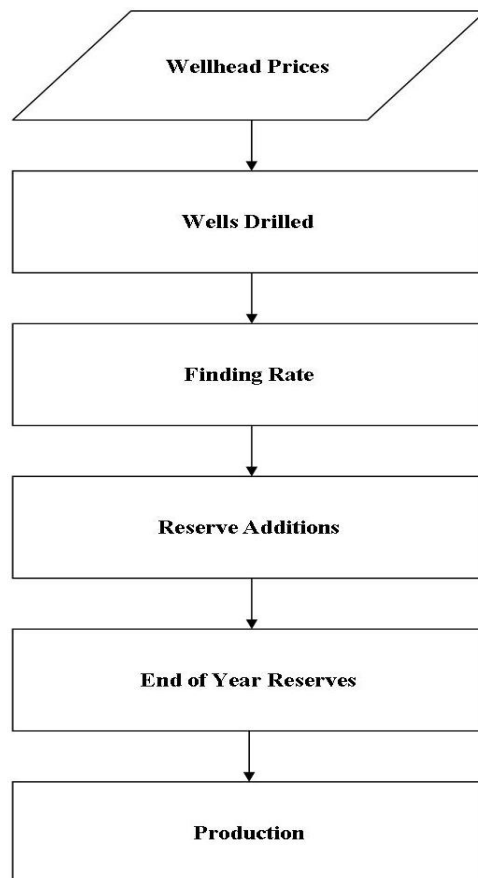
Conventional Gas from the Western Canadian Sedimentary Basin

Wells Determination

The total number of successful conventional natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price, remaining resources, and last year's production-to-reserve ratio as follows:

$$SUCWELL_t = \exp(\beta 0) * CN\_PRC00_t^{\beta 1} * \exp(\beta 2 * URRCAN_t)$$
$$* \exp(\beta 3 * (OGPRDCAN_{t-1} / CURRESCAN))$$

(44)

where,

$SUCWELL_t$	=	total conventional successful gas wells completed in Western Canada in year t
CN_PRC00_t	=	price per Mcf of natural gas[18] in 2000 US dollars in year t

---

[18] In the fall of 2007 legislation was passed to increase the royalty rate in Alberta from 25 percent to 30 percent. Since royalty rates are not explicitly modeled for Canada, the effect of this was modeled by decreasing the price that would be seen in Alberta for the purposes of making drilling decisions by 0.933 (ROYADJ), which is equivalent to (1-.3)/(1-.25), starting in 2009 when the legislation takes affect.

$$\begin{array}{rcl}
\text{URRCAN}_t & = & \text{remaining conventional gas recoverable resources in year t in western} \\
& & \text{Canada in (Bcf)} \\
\text{OGPRDCAN}_{t-1} & = & \text{conventional gas production in the previous forecast year (million cubic} \\
& & \text{feet)} \\
\text{CURRESCAN} & = & \text{proved reserves of conventional gas at the beginning of the previous} \\
& & \text{forecast year (million cubic feet)} \\
\beta_0 & = & \text{econometrically estimated parameter (3.95973, Appendix D)} \\
\beta_1 & = & \text{econometrically estimated parameter (0.506617, Appendix D)} \\
\beta_2 & = & \text{econometrically estimated parameter (0.000011634, Appendix D)} \\
\beta_3 & = & \text{econometrically estimated parameter (33.7870, Appendix D)}
\end{array}$$

The number of wells is restricted to increase by no more than 30 percent annually. Unfortunately recent significant increases in exploratory and development costs are not captured in this equation. In an effort to reflect the potential impact, without reestimating the equation, the resulting number of wells was multiplied by a factor equal to the average U.S. drilling costs in 2003 (before the significant cost increase) divided by the costs in the current forecast year, all raised to an assumed power of 0.1.

Reserve Additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is, all else being constant, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption based, while the current version was econometrically estimated using the following:

$$\text{FRCAN}_t = \exp\{(1-\rho)*\beta 0 + \beta 1*\text{URRCAN}_t\}*\exp\{-\rho*\beta 1*\text{URRCAN}_{t-1}] \tag{45}$$

where,

$$\begin{array}{rcl}
\text{FRCAN}_t & = & \text{finding rate in year t (Bcf per well)} \\
\text{URRCAN}_t & = & \text{remaining conventional gas recoverable resources in year t in western} \\
& & \text{Canada in (Bcf)} \\
\beta_0 & = & \text{econometrically estimated parameter (-2.43218, Appendix D)} \\
\beta_1 & = & \text{econometrically estimated parameter (0.0000166026, Appendix D)} \\
\rho & = & \text{serial correlation parameter (0.384096, Appendix D)}
\end{array}$$

Remaining conventional gas recoverable resources are initialized in 2004 at 92,000 Bcf and set each year thereafter as follows:

$$\text{URRCAN}_t = \text{RESBASE}*(1+\text{RESTECH})^T - \text{CUMRCAN}_t \tag{46}$$

where,

RESBASE   =   initial recoverable resources in 2004 (set at 95,830 Bcf)[19]
RESTECH   =   assumed rate of increase, primarily due to the contribution from tight gas
                formations, but also attributable to technological improvement (1.5 percent
                or 0.0015)
CUMRCAN_t =   cumulative reserves added since initial year of 2004 in Bcf

Total reserve additions in period t are given by:

$$\text{RESADCAN}_t = \text{FRCAN}_t * \text{SUCWELL}_t \qquad (47)$$

where,

RESADCAN_t =   Reserve additions in year t, in BCF
FRCAN_{t-1} =   Finding rate in the previous year, in BCF per well
SUCWELL_t =   Successful gas wells drilled in year t

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$\text{RESBOYCAN}_{t+1} = \text{CURRESCAN}_t + \text{RESADCAN}_t - \text{OGPRDCAN}_t \qquad (48)$$

where,

RESBOYCAN_{t+1} =   Beginning of year reserves for t+1 (end of year reserves for t), in BCF
CURRESCAN_t =   Beginning of year reserves for t, in BCF
RESADCAN_t =   Reserve additions in year t, in BCF
OGPRDCAN_t =   Production in year t, in BCF
t =   forecast year

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the expected production-to-reserve ratio for new wells are adjusted accordingly.

Gas Production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Conventional gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. While econometrically based equations have been used in the past to derive an expected extraction rate, the current version of the model assumes an average historically based rate throughout the forecast period, set to the average over the last 6 historical years.

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[19]Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004.

Allocation of Canadian Natural Gas Production to Canada and the United States

The purpose of Canadian natural gas production is to meet both Canadian demands and exports to the United States. The methodology used to define Canadian natural gas production and exports is intrinsic in the North American market equilibrium that occurs in the NGTDM. Thus, the details of this procedure are provided in the methodology documentation for that module.

Mexican Gas Trade

Mexican gas trade is a highly complex issue. A range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is great enough that not only is the magnitude of flow for any future year in doubt, but also the direction of flow.

Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the FNGSS. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico. Three new LNG facilities in Mexico, one at Altamira (700 Mmcf/day capacity) on the Gulf Coast that opened in 2006, one in Baja California, Mexico (1 Bcf/day capacity, half for U.S. market and half for Mexican market) that is currently under construction and assumed to begin operation in 2008, and a third 500 Mmcf/day terminal (not site-specific) along Mexico's West coast that is assumed to begin operation in 2011 are included in AEO2008. Future expansion of the Baja terminal is determined endogenously. These assumptions have been developed from an assessment of current and expected industry and market circumstances as indicated in announcements and reports from Mexican government officials, industry announcements, and articles or reports in relevant publications. Excess supply is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.

Liquefied Natural Gas

Liquefaction is a process whereby natural gas is cooled to minus 260 degrees Fahrenheit, causing it to be converted from a gas to a liquid. This significantly reduces its volume making it possible to transport to distant markets. Liquefaction allows stranded gas, or gas that would otherwise be inaccessible due either to lack of nearby markets or lack of pipeline infrastructure to deliver it to local markets, to be monetized. LNG imports into the United States have grown over the past several years, and prospects for continued growth are good. Various factors have contributed to the recent re-emergence of LNG as an economically viable source of energy, including contracts with pricing and delivery flexibility, the growth of the spot market for LNG, a growing preference toward natural gas due to the lesser environmental consequences for burning it versus other fossil fuels, and a desire for diversification and security of energy supply. Relatively higher recent natural gas prices have provided further impetus. At present, there are five new U.S. LNG receiving terminals under construction, four along the Gulf Coast and one off the coast of New England. Numerous others have received approval from the appropriate regulatory authorities (although regulatory approval does not mean that they will be built), and others have been, and continue to be, proposed. The assumption for AEO2008 is that those under construction will proceed, with the construction of any additional terminals determined endogenously.

A detailed description of the algorithm employed for determining U.S. imports of LNG is provided in the NGTDM documentation report. In brief, LNG imports into the United States are determined using a set of regional, annual supply curves for LNG within the market equilibrium routine in the NGTDM. The supply curves are established by determining the implied marginal prices within a linear programming (LP) structure which minimize the cost of importing a selected level and regional distribution of LNG imports in a year. The LP is solved multiple times to establish a series of points, or price/quantity pairs, along each of the regional supply curves. The supply curves are drawn by connecting the points. Within the LP, costs are represented using a series of step curves for regasification in each U.S. receiving region represented, as well as for production and liquefaction for each producing country/region represented. Shipping costs are similarly represented between each producing and receiving point, as is reasonable.

Exports of LNG via Alaska to Japan are still established exogenously to OGSM. The level of annual exports is set exogenously based on recent history and announcements relative to the potential extension and/or expiration of the export license. While the current license will expire early in 2009, the government of Alaska and a group of producers have reached an agreement that increases the chance of the Department of Energy extending the license for another two years. While EIA generally assumes current laws and regulations, an exception was made in this case given the increased likelihood of an extension.

Appendix 3-A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (eg., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation 3A-1).

$$DCF_T = (PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP$$
$$- PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \qquad (3A\text{-}1)$$

where,

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation 3A-1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1] times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private

---

[1]The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$\text{WACC} = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{3A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by:

$$\text{disc} = \frac{(1+\text{WACC})}{(1+\pi_e)} - 1 \tag{3A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the foecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$\text{PVREV}_{T,k} = \sum_{t=T}^{T+n} \left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+\text{disc}}\right]^{t-T} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ \text{COPRD if secondary fuel} \end{cases} \tag{3A-4}$$

where,

$$
\begin{array}{rcl}
k & = & \text{fuel type (oil or natural gas)} \\
t & = & \text{time period} \\
n & = & \text{number of years in the evaluation period} \\
\text{disc} & = & \text{expected discount rate} \\
Q & = & \text{expected production volumes} \\
P & = & \text{expected net wellhead price} \\
\text{COPRD} & = & \text{co-product factor.}[3]
\end{array}
$$

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

The present value of the total expected revenue generated from the representative project is:

$$\text{PVTREV}_T = \text{PVREV}_{T,1} + \text{PVREV}_{T,2} \tag{3A-5}$$

where,

$\qquad \text{PVREV}_{T,1} \quad = \quad$ present value of expected revenues generated from the primary fuel

---

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

$$PVREV_{T,2} = \text{present value of expected revenues generated from the secondary fuel.}$$

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to:

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{3A-6}$$

where,

$$ROYRT = \text{royalty rate, expressed as a fraction of gross revenues.}$$

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:

$$PVPRODTAX_T = PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2}$$
$$* (1 - ROYRT_2) * PRODTAX_2 \tag{3A-7}$$

where,

$$PRODTAX = \text{production tax rate.}$$

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 dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period.)

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor, 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:

---

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

$$PVDRILLCOST_T = \sum_{t=T}^{T+n} \Big[\big[COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_t$$

$$+ COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \qquad (3A-8)$$

$$+ COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \big] * \Big(\frac{1}{1 + disc} \Big)^{t-T} \Big]$$

where,

COSTEXP	=	drilling cost for a successful exploratory well
SR	=	success rate (1=exploratory, 2=developmental)
COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for a oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells. The present value of expected lease equipment cost is

$$PVEQUIP_T = \sum_{t=T}^{T+n} \Big[EQUIP_T * (SR_1 * NUMEXP_t + SR_2 * NUMDEV_t) * \Big[\frac{1}{1 + disc} \Big]^{t-T} \Big] \qquad (3A-9)$$

where,

EQUIP = lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as:

$$PVKAP_T = \sum_{t=T}^{T+n} \Big[KAP_t * \Big[\frac{1}{1 + disc} \Big]^{t-T} \Big] \qquad (3A-10)$$

where,

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n}\left[OPCOST_T * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1+disc}\right)^{t-T} \right] \quad (3A-11)$$

where,

$\qquad$ OPCOST $\quad = \quad$ operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n}\left[COSTABN_T * \left[\frac{1}{1+disc}\right]^{t-T} \right] \quad (3A-12)$$

where,

$\qquad$ COSTABN $\quad = \quad$ abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

---

[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

Key changes in the tax provisions under the tax legislation of 1988 include:

- ! Windfall Profits Tax on oil was repealed,

- ! Investment Tax Credits were eliminated, and

- ! Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table 3A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$PVTAXBASE_T = \sum_{t=T}^{T+n} \left[\left(TREV_t - ROY_t - PRODTAX_t - OPCOST_t - ABANDON_t - XIDC_t \right. \right.$$

$$\left. \left. - AIDC_t - DEPREC_t - DHC_t \right) * \left(\frac{1}{1 + disc} \right)^{t-T} \right]$$

(3A-13)

where,

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

$TREV_t$, ROY_t, $PRODTAX_t$, $OPCOST_t$, and $ABANDON_t$ are the nondiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for purpose of determining corporate income tax liability at the State and Federal level.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

---

[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table 3A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included. Expected expensed IDC's are defined as follows:

$$
\begin{aligned}
XIDC_t = \; & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t \\
& + COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t
\end{aligned}
\tag{3A-14}
$$

where,

COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well

Table 3A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s **5-year SLM**[d] 20 percent of IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; firsst 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.

---

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

DVKAP = fraction of developmental drilling costs that are tangible and must be depreciated

NUMDEV = number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. These costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year, referred to as the 5-year Straight Line Method (SLM) with half year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, then costs are recovered using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by:

$$\text{AIDC}_t = \sum_{j=\beta}^{t} \Big[\big(\text{COSTEXP}_T * (1 - \text{EXKAP}) * \text{XDCKAP} * \text{SR}_1 * \text{NUMEXP}_j$$
$$+ \text{COSTDEV}_T * (1 - \text{DVKAP}) * \text{XDCKAP} * \text{SR}_2 * \text{NUMDEV}_j \big)$$
$$* \text{DEPIDC}_t * \left(\frac{1}{1+\text{infl}} \right)^{t-j} * \left(\frac{1}{1+\text{disc}} \right)^{t-j} \Big], \quad\quad (3A-15)$$

$$\beta = \begin{cases} T \text{ for } t \leq T + m - 1 \\ t - m + 1 \text{ for } t > T + m - 1 \end{cases}$$

where,

j = year of recovery

β = index for write-off schedule

DEPIDC = for t # n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period

infl = expected inflation rate[8]

disc = expected discount rate

m = number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$\text{DHC}_t = \text{COSTDRY}_{T,1} * (1 - \text{SR}_1) * \text{NUMEXP}_t + \text{COSTDRY}_{T,2} * (1 - \text{SR}_2) * \text{NUMDEV}_t \quad\quad (3A-16)$$

where,

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of XIDC_t, OPCOST_t, ABANDON_t, and DHC_t.

---

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table 3A-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.

Table 3A-2.   MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$
\begin{aligned}
DEPREC_t = \sum_{j=\beta}^{t} \Big[\big[(COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j \\
+ (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \big] \\
* DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big],
\end{aligned}
\tag{3A-17}
$$

$$
\beta = \begin{cases} T \text{ for } t \le T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases}
$$

where,

j	=	year of recovery
β	=	index for write-off schedule
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[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$
PVSIT_T = PVTAXBASE_T * STRT \tag{3A-18}
$$

where,

PVTAXBASE	=	present value of expected taxable income (Equation 3A-14)
STRT	=	state income tax rate.

The present value of expected federal corporate income tax is calculated using the following equation:

---

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \qquad (3A\text{-}19)$$

where,

FDRT   =   federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

Appendix 3B. Unconventional Gas Recovery Supply Submodule

INTRODUCTION

The UGRSS is the unconventional gas component of the EIA=s Oil and Gas Supply Module (OGSM), one component of EIA=s National Energy Modeling System (NEMS). The UGRSS is a play level model that specifically analyzes the three major unconventional resources - coalbed methane, tight gas sands, and gas shales. This appendix describes the UGRSS in detail. The following major topics are presented concerning the model:

> ! Model purpose
> ! Model overview and rationale
> ! Model structure
> ! Data sources

The first section discusses the purpose of the UGRSS. The second section explains the rationale for developing the UGRSS, and how the model allows OGSM to address various issues associated with unconventional natural gas exploration and production. The third section discusses the actual modeling structure in detail. The fourth section discusses the data sources for the model. In this section the unconventional gas resource base is presented in detail with the underlying assumptions. All dollars ($) are in are in 1996 constant dollars unless stated otherwise.

MODEL PURPOSE

The Unconventional Gas Recovery Supply Submodule (UGRSS) offers EIA the ability to analyze the unconventional gas resource base and its potential for future economic production under differing technological circumstances. The UGRSS was built exogenously from the National Energy Modeling System (NEMS) but now functions as a submodule within the NEMS Oil and Gas Supply Module (OGSM).

Figure 3B-1
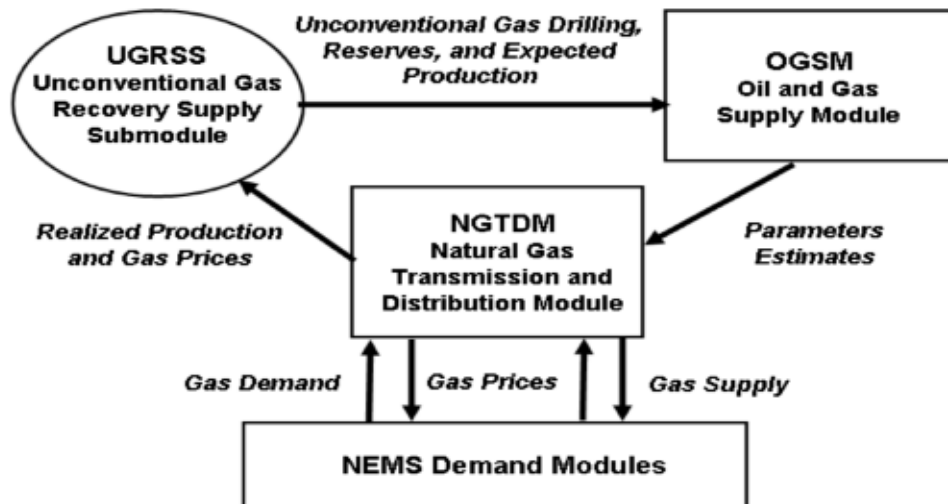
The UGRSS uses pricing data from EIA=s NGTDM, resource data from the USGS[1] (as modified by Advanced Resources, International), and cost data from various sources including the API=s JAS. An illustration of how the UGRSS interfaces with the EIA/NEMS energy modules is shown in Figure 3B-1.

Unconventional natural gas -- natural gas from coal seams, natural gas from organic shales, and natural gas from tight sands -- was thought of as an Ainteresting concept@ or Ascientific curiosity@ not long ago. To spur interest in the development of unconventional gas, the U.S. Government offered tax credits (Section 29) for any operator attempting to develop this type of resource. Indeed, this did interest many operators and unconventional gas resources began to be developed. Through research and development (R&D), individual technology was developed to enable unconventional resources to be economically developed and placed on production. These technologies began to be applied in different regional settings yielding successful results.

In the 1995 USGS National Assessment, unconventional gas represented the largest onshore technically recoverable natural gas resource (Table 3B-1). Figures 3B-2 through 3B-4 illustrate the current basins in which each type of resource exists. Since 1992, production in each unconventional gas resource has increased and by 1996 unconventional gas made up 20 percent of natural gas production and 30 percent of natural gas reserves in the United States. The increase in the contribution of unconventional natural gas to the U.S. production and reserve baseline is apparent and growing. This fact makes the capability to understand the present unconventional gas resource base and the ability to predict future energy scenarios involving unconventional gas an invaluable element in future DOE/EIA energy modeling.

Prior to the development of the current UGRSS, the estimates of unconventional gas production in the Annual Energy Outlook (AEO) were based on the results of econometric equations. OGSM forecasted representative drilling costs and drilling activities (wells) by region and resource type, including unconventional gas. Based on historical trends in reserve additions per well and a series of discovery process equations, these projected drilling levels generated reserve additions, and thereby production, for each resource type. This approach is somewhat limited when applied to unconventional gas, however. Because significant exploration and development in this resource has been realized only recently, there exists minimal historical activity to effectively establish a trend from which to extrapolate into the future. Furthermore, technological changes have substantially changed the productivity and economics of this resource area in recent years. Consequently, the development of a specialized, geology and engineering based unconventional gas model that accounts for technological advances was deemed necessary.

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[1]A1995 National Assessment of United States Oil and Gas Resources,@ U.S. Geological Survey (USGS), National Oil and Gas Resource Assessment Team, U.S. Geological Survey Circular 1118, (1995); Basin-by-basin Resource Assessment updates through 2003, USGS - http://energy.cr.usgs.gov/oilgas/noga/assessment/bybasin.htm .

Table 3B-1. USGS 1995 National Assessment

Background

- The 1995 National Assessment of U.S. Oil and Gas Resources by the USGS established unconventional gas (continuous-type deposits) as the largest undiscovered onshore technically recoverable natural gas resource:

  - Continuous-Type Deposits 358 Tcf
    - CBM   (50 Tcf)
    - Gas Shales (49 Tcf)
    - Tight Sands* (260 Tcf)
  - Reserve Growth 322 Tcf
  - Undiscovered Conventional 259 Tcf
    Resources

  *Includes low permeability chalks

- Significantly, the 1995 Assessment did not quantitatively assess many large, already producing unconventional gas deposits, such as:
  - Wind River Basin, Tertiary and Upper Cretaceous Tight Sands
  - Fort Worth Basin, Barnett Shale
  - Green River Basin, Deep Coalbed Methane

Figure 3B-2: U.S. Lower 48 Coalbed Methane Basins

Legend:
- Established CBM Basin (green)
- Emerging CBM Basin (red)
- Frontier CBM Basin (tan)

JAB00548.PPT
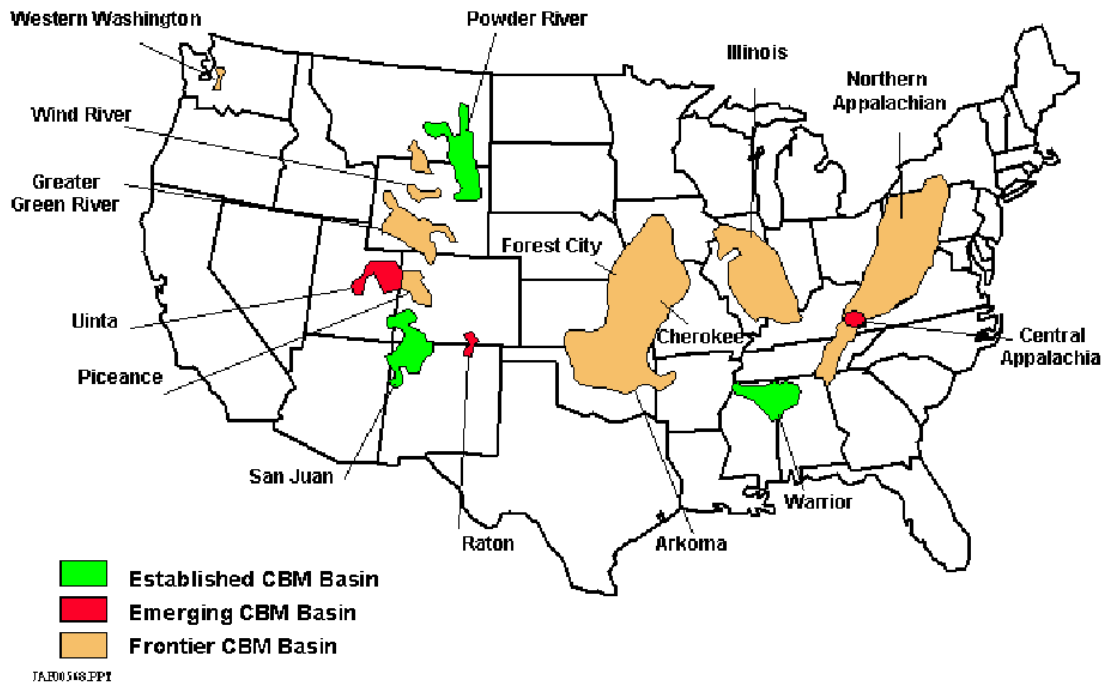
Source: Advanced Resources, International

Figure 3B-3: U.S. Lower 48 Tight Gas Basins

JAB00548.PPT
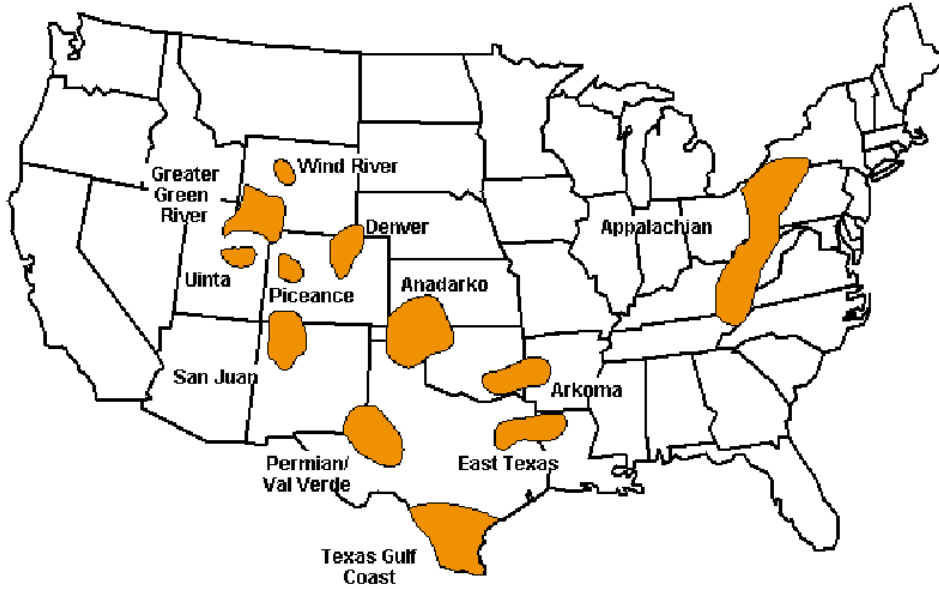
Source: Advanced Resources, International

Figure 3B-4: U.S. Lower 48 Gas Shale Basins
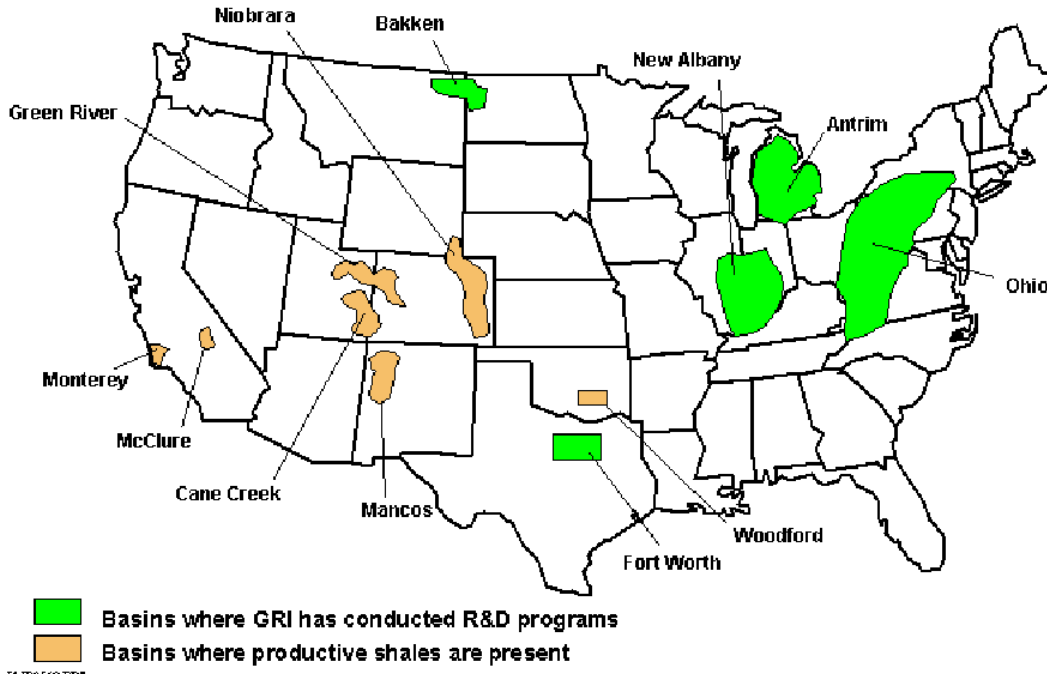
Source: Advanced Resources, International

MODEL OVERVIEW & RATIONALE

The growth of unconventional gas activities in the recent past has been so significant that DOE/EIA needed a better understanding of the quantity of unconventional resources and the technologies associated with its production. Figures 3B-5 and 3B-6 and Table 3B-7 illustrate growth in coalbed methane, tight gas and gas shales production. By 1996, unconventional gas made up 20 percent of US natural gas production and 30 percent of US natural gas reserves. Much of this growth could be attributed to technological advances from R&D in unconventional gas supported by the DOE, the Gas Research Institute (GRI), and industry in the late 1980's and early 1990's.

The USGS included unconventional natural gas in their 1995 National Assessment. However, their estimates did not take into account future changes in technologies effecting unconventional gas. Because much of the unconventional gas resource is Atechnology constrained@ rather than Aresource constrained,@ it is important to quantify the existing unconventional gas resource base and explore the technologies that are needed to enhance the development of unconventional natural gas. The UGRSS incorporates the effect of different technologies in different forward-looking scenarios to quantify the future of unconventional gas.

Figure 3B-5

Growth in Coalbed Methane
Wells and Production

Producing Wells

- 1992*: 5,278
- 1993: 5,926
- 1994: 6,287
- 1995: 6,700(e)
- 1996: 7,000(e)

Annual Production (Bcf)

- 1992*: 562
- 1993: 748
- 1994: 862
- 1995: 956
- 1996: 1003
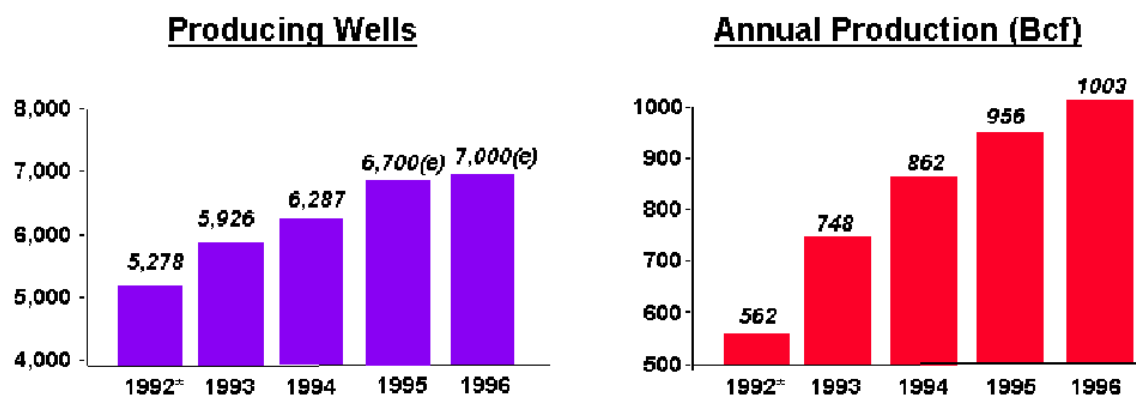
*1992 was the end of the Sec. 29 tax credit.

Source: Advanced Resources, International

Figure 3B-6

Gas Shales Production and Well Completions

Annual Production

Well Completions

Basins	1992	1993	1994	1995
Michigan (Antrim)	1,193	418	507	850
Appalachian (Devonian)	462	411	336	300
Fort Worth (Barnett)	19	40	41	60
Other*	35	71	28	90
Total	**1,709**	**940**	**912**	**1,300**
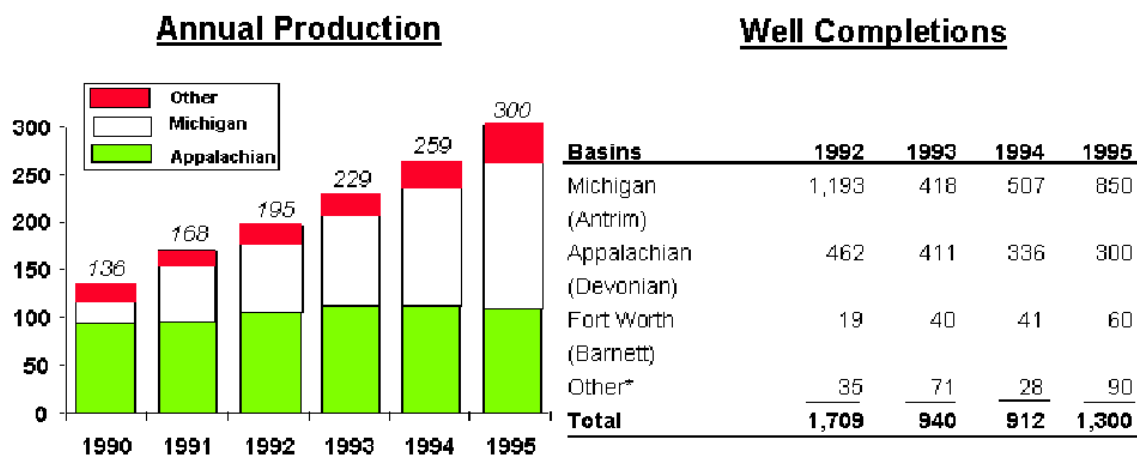
*Illinois (New Albany) and Denver (Niobrara).

Source: Advanced Resources, International

Table 3B-2

Tight Gas Production -- 1992-1996

Basins/Regions	Annual Production (Bcf)				
	1992	1993	1994	1995	1996
Arkla	48	51	52	50	50
East Texas	339	365	370	370	370
Texas Gulf Coast	435	468	474	500	520
Wind River	11	11	11	20	30
Green River	231	295	335	327	360
Denver	71	76	77	75	75
Uinta	35	66	59	56	60
Piceance	31	33	34	32	41
Anadarko	213	230	232	220	220
Permian Basin	235	253	255	260	260
San Juan	321	350	342	330	340
Williston	8	8	8	8	20
Appalachian	419	396	396	390	397
TOTALS	**2,397**	**2,603**	**2,645**	**2,638**	**2,743**

Source: Advanced Resources, International

DATA SOURCES

The UGRSS borrows much of its resource data from the USGS=s 1995 National Assessment. (Advanced Resources International (ARI) prepared much of the resources assessment for coalbed methane within that study). Another source for unconventional gas resource data was ARI=s own internal database. The UGRSS incorporates all of the USGS designated continuous-type plays into the model structure (continuous-type deposits is the USGS term for unconventional gas) and adds some frontier plays that were not quantitatively assessed by the USGS. Because of the geologic and engineering base for the model=s structure, many ARI internal basin and play level evaluations, reservoir simulations and history-matching based well performances were included to modify the existing data. Further refinements to some of the estimated ultimate recoveries (EUR=s) per well, a key component in deriving resource estimates, were provided by an independent expert reviewer, Harry Vidas of Energy and Environmental Analysis, Inc . These modifications provide the UGRSS with up-to-date and expert resource evaluation to base its future projections upon. Detailed UGRSS resource tables with resources broken down by component are provided in Tables 3B-3 to 3B-5.

The estimates used for current and expected activity in production and reserves within the UGRSS were derived from in-depth analysis of State survey data, industry inputs, Petroleum Information /Dwights Energy Data (PI/Dwights) completion and production records and EIA=s annual reserves report. These data are linked to the NEMS historic accounting module.

The data concerning costs and economics were developed by ARI from extensive work with industry producers in tight gas, coalbed methane and gas shale basins, plus the API=s JAS. They also reflect some recommended modifications by an independent expert reviewer, Leo Giangiacomo of Extreme Petroleum Technology, Inc.

The determinations of how technology will affect the model, the timing of these technology impacts and current and future environmental constraints are the significant variables that determine the output of the UGRSS. These variables were developed by ARI to incorporate R&D programs being conducted by the DOE, GTI and industry that lead to significant technology progress. These variables will each be explained in detail in Appendix 3-c.

Drilling allocations establish a pace of well drilling for economically feasible gas plays based on play profitability, play maturity, and aggregate U.S. oil and gas upstream expenditures. The baseline data and these determinations are linked to the other drilling projections within OGSM.

The major model outputs are drilling, reserve additions, reserves, and expected production (productive capacity) by OGSM regions. These outputs are linked to directly to OGSM and, through OGSM, indirectly to NGTDM, the natural gas price/supply component of the NEMS integrating framework.

Table 3B-3. Tight Sands Resource Base: Detailed Breakdown

Play #	Basin	Play	A Basin Area (Square Miles)	B Developed Cells (1/1/1996)	C Wells per Square Mile	D Estimated Ultimate Recovery (Bcf/Well)	E Success Rate	F Play Prob-ability	G Official No Access	H Undev'd. Resources 1/1/1996 (Bcf)	I USGS 30-Year Factor	J 30-Year Undev'd. Resources 1/1/1996 (Bcf)	K Expected Reserve Growth 1/1/1996 (Bcf)	L Unproved Resources 1/1/1996 (Bcf)	M Adj.'s for Tech. (+) &	N Unproved Resources 1/1/2006 (Bcf)
										H = (A*C-B)*D*E*F*(1-G)			L=J+K			N=L+M
1	Uinta Basin	Tertiary East	1600	928	16	0.69	95%	100%	16.34%	13530	29%	3924	28	3952	-744	3208
2		Tertiary West	1603	0	8	4.85	95%	100%	57.39%	25177	21%	5287	0	5287	224	5511
3		Basin Flank Mesaverde	1708	22	8	1.18	87%	100%	33.38%	9330	50%	4665	3	4668	-168	4500
4		Deep Synclinal Mesaverde	2893	3	8	1.18	67%	50%	2.11%	8955	29%	2597	0	2597	87	2684
5	Wind River Basin	Fort Union/Lance Shallow	1500	59	8	1.39	86%	100%	0.00%	14274	100%	14274	6	14280	-331	13949
6		Mesaverde/Frontier Shallow	250	94	4	1.51	56%	100%	0.00%	766	100%	766	18	784	-98	686
7		Fort Union/Lance Deep	2500	11	4	0.64	86%	80%	9.42%	3984	100%	3984	0	3984	143	4127
8		Mesaverde/Frontier Deep	250	23	4	2.34	75%	50%	9.45%	776	100%	776	2	778	13	791
9	Appalacian Basin	Clinton/Medina High	14773	22545	8	0.30	90%	100%	0.00%	25823	50%	12911	-1	12910	-1425	11485
10		Clinton/Medina Moderate/Low	27281	55500	15	0.09	86%	100%	0.00%	27378	52%	14236	0	14236	2232	16468
11		Clinton/Medina Berea Sandstone	51863	60000	8	0.21	90%	75%	0.00%	50308	23%	11571	0	11571	368	11939
12		Upper Devonian High	12775	53940	10	0.25	85%	100%	0.00%	15685	46%	7215	310	7525	-683	6842
13		Upper Devonian Moderate/Low	29808	55000	10	0.07	85%	100%	0.00%	14463	32%	4628	0	4628	1999	6627
14		Upper Devonian Tuscarora Sandstone	42495	83	8	0.82	75%	75%	0.00%	156768	2%	2665	0	2665	-44	2621
15	Denver Basin	Deep J Sandstone	3500	8809	16	0.29	85%	100%	1.04%	11512	90%	10361	134	10495	-1261	9234
16	Greater Green River Basin	Fort Union/Fox Hills	3858	45	8	0.84	72%	81%	12.11%	13270	8%	995	2	997	-94	903
17		Lance	5500	25	8	7.89	95%	100%	10.96%	293484	12%	35218	3	35221	-8175	27046
18		Lewis	5172	512	8	1.57	92%	100%	6.28%	55318	25%	13830	33	13863	-147	13716
19		Shallow Mesaverde (1)	5239	1056	4	1.49	90%	100%	7.80%	24605	53%	13041	185	13226	-1559	11667
20		Shallow Mesaverde (2)	6814	0	8	0.80	35%	100%	8.28%	14000	49%	6860	0	6860	268	7128
21		Deep Mesaverde	16416	153	4	0.49	60%	75%	8.14%	13269	15%	1990	3	1993	68	2061
22		Frontier (Moxa Arch)	2334	2144	8	1.43	94%	100%	14.83%	18923	25%	4731	190	4921	-1189	3732
23		Frontier (Deep)	15619	14	4	3.08	75%	75%	9.19%	98273	9%	8845	0	8845	323	9168
24	Piceance Basin	South Basin Williams Fork/Mesaverde	1008	414	32	1.30	95%	100%	8.56%	35958	87%	31283	2	31285	-13523	17762
25		North Basin Williams Fork/Mesaverde	1008	0	8	1.85	87%	100%	1.98%	12722	87%	11068	-23	11045	-6418	4627
26		Iles/Mesaverde	972	189	8	0.64	80%	100%	4.81%	3698	40%	1479	2	1481	422	1903

27	**LA/MS Salt Basin**	East Texas Cotton Valley/Bossier	2730	6812	12	1.66	95%	100%	0.00%	40920	100%	40920	339	41259	-9658	31601
28	**Arkoma Basin**	Arkoma - Atoka	1000	2455	8	1.55	90%	100%	0.00%	7735	75%	5801	233	6034	-1931	4103
29	**San Juan Basin**	Picture Cliffs	6558	5821	4	0.51	90%	100%	1.83%	9197	25%	2299	91	2390	-315	2075
30		Central Basin/Mesaverde	3689	5118	8	0.86	95%	100%	1.76%	19580	50%	9790	305	10095	-2301	7794
31		Central Basin/Dakota	3918	4880	6	0.58	95%	100%	0.82%	10179	56%	5700	192	5892	-827	5065
32	**Northern Great Plains Basin**	High Potential	2000	1838	4	0.73	88%	100%	4.29%	3789	100%	3789	-69	3720	-772	2948
33		Moderate Potential	2000	200	4	0.40	50%	80%	4.24%	1195	100%	1195	0	1195	43	1238
34		Low Potential	3000	83	4	0.25	30%	75%	1.05%	663	100%	663	0	663	33	696
35	**Columbia Basin**	Basin Centered.	1500	0	8	1.50	70%	50%	0.00%	6300	100%	6300	0	6300	176	6476
36	**Anadarko Basin**	Cleveland	1500	1207	4	1.09	84%	100%	0.00%	4388	100%	4388	-15	4373	-520	3853
37		Cherokee/Redfork	1500	3350	4	1.07	90%	100%	0.00%	2552	100%	2552	154	2706	-1385	1321
38		Granite Wash/Atoka	1500	641	4	2.06	91%	100%	0.00%	10046	100%	10046	9	10055	-1815	8240
39	**Texas Gulf Basin**	Vicksburg	600	2011	8	2.83	94%	100%	0.00%	7419	100%	7419	284	7703	-3958	3745
40		Wilcox/Lobo	1500	5103	8	1.91	92%	100%	0.00%	12119	100%	12119	430	12549	-4978	7571
41		Olmos	2500	1038	4	0.52	83%	100%	0.00%	3868	100%	3868	-62	3806	-524	3282
42	**Permian Basin**	Canyon	6000	6651	8	0.26	75%	100%	0.00%	8063	100%	8063	136	8199	-843	7356
43		Abo	1500	2091	8	1.19	75%	100%	0.00%	8844	100%	8844	-203	8641	-2176	6465

Source: Advanced Resources, International

Table 3B-4. Gas Shales Resource Base: Detailed Breakdown

Play #	Basin	Play	A Basin Area (Square Miles)	B Developed Cells 1/1/1996	C Wells per Square Mile	D Estimated Ultimate Recovery 1/1/1996 (Bcf/Well)	E Success Rate 1/1/1996	F Play Probability	F Official No Access	H Undev'd. Resources 1/1/1996 (Bcf)	I USGS 30-Year Factor	J 30-Year Undev'd. Resources 1/1/1996 (Bcf)	K Expected Reserve Growth 1/1/1996 (Bcf)	L Unproved Resources 1/1/1996 (Bcf)	M Adj.'s for Tech. (+) & Dev.(-) (Bcf)	N Unproved Resources 1/1/2006 (Bcf)
										H = (A*C-B)*D*E*F*(1-G)				L=I*J+K		N=L+M
1	Appalachian Basin	Big Sandy Central	8800	8344	6	0.30	86%	100%	0.00%	11470	52%	5964	825	6789	-1890	4899
2		Big Sandy Extension	7000	10658	6	0.25	86%	100%	0.00%	6739	52%	3504	210	3714	-249	3465
3		Greater Siltstone Area	22899	4600	7	0.10	59%	100%	0.00%	9186	19%	1745	0	1745	199	1944
4		Low Thermal Maturity	45844	3500	8	0.06	74%	80%	0.00%	12903	19%	2452	0	2452	1645	4097
5	Michigan Basin	Antrim - Developing Area	2000	7197	8	0.32	95%	100%	0.00%	2676	100%	2676	826	3502	-942	2560
6		Antrim - Undeveloped Area	8000	0	8	0.30	50%	80%	0.00%	7680	100%	7680	0	7680	311	7991
7	Illinois Basin	New Albany	5000	134	4	0.25	50%	80%	0.00%	1987	100%	1987	0	1987	53	2040
8		Cincinatti Arch - Devonian Shales	6000	0	4	0.12	50%	50%	0.00%	720	100%	720	0	720	27	747
9	Williston Basin	Shallow Niobrara	10000	0	2	0.42	58%	75%	4.01%	3507	100%	3507	0	3507	343	3850
10	Fort Worth Basin	Barnett - Core Area	1555	411	12	1.14	95%	100%	0.00%	19764	100%	19764	61	19825	-73	19752
11		Barnett - Extension 1	2450	0	4	1.72	75%	100%	0.00%	12642	100%	12642	0	12642	-1138	11504
12		Barnett - Extension 2	2450	0	12	1.39	50%	100%	0.00%	20433	100%	20433	0	20433	-13681	6752
13	San Juan Basin	Lewis Shale	7506	0	6	0.50	95%	100%	0.00%	21392	34%	7273	0	7273	3141	10414
14	Midcontinent	Fayetteville - Central	5300	0	8	1.60	94%	100%	0.00%	63770	39%	24870	0	24870	1118	25988
15		Fayetteville - West	5400	0	8	0.80	88%	100%	0.00%	30413	10%	3041	0	3041	153	3194
16		Woodford - Western Arkoma	2900	0	4	2.80	90%	100%	0.00%	29232	43%	12570	0	12570	560	13130
17		Woodford - Central OK Fold Belt	1800	0	4	1.00	86%	100%	0.00%	6192	41%	2539	8	2547	117	2664

Source: Advanced Resources, International

Table 3B-5. Coalbed Methane Resource Base: Detailed Breakdown

Play #	Basin	Play	A Basin Area (Square Miles)	B Developed Cells (1/1/1996)	C Wells per Square Mile	D Estimated Ultimate Recovery (Bcf/Well)	E Success Rate	F Play Probability	G Official No Access	H Undev'd. Resources 1/1/1996 (Bcf)	I USGS 30-Year Factor	J 30-Year Undev'd. Resources 1/1/1996 (Bcf)	K Expected Reserve Growth 1/1/1996 (Bcf)	L Unproved Resources 1/1/1996 (Bcf)	M Adj.'s for Tech. (+) & Dev.(-) (Bcf)	N Unproved Resources 1/1/2006 (Bcf)
										H = (A*C-B)*D*E*F*(1-G)		J=I*H		L=J+K		N=L+M
1	Uinta Basin	Ferron	400	100	8	1.56	93%	100%	11%	4003	80%	3202	271	3473	-869	2604
2		Blackhawk	586	40	8	0.31	58%	100%	5%	794	74%	588	0	588	-132	456
3		Sego	534	0	4	0.61	50%	80%	10%	469	80%	375	0	375	-61	314
4	Raton Basin	Northern Basin	470	13	8	0.70	10%	75%	0%	197	100%	197	0	197	-27	170
5		Purgatory River	360	82	8	0.62	75%	100%	0%	1301	100%	1301	77	1378	715	2093
6		Southern Basin	386	36	8	0.75	75%	100%	2%	1682	100%	1682	0	1682	1613	3295
7	Powder River Basin	Wyodak/Upper Fort Union	3600	1498	20	0.27	80%	100%	1%	15076	97%	14624	84	14708	-3957	10751
8		Big George/Lower Fort Union	2880	11	16	0.52	77%	100%	1%	18262	61%	11140	0	11140	-1393	9747
9		Wasatch	216	0	8	0.11	31%	100%	1%	58	99%	58	0	58	-1	57
10		Central Basin	3870	675	8	0.35	79%	100%	0%	8374	46%	3852	870	4722	-1694	3028
11		NAB - High	3817	34	12	0.25	70%	100%	0%	8010	10%	801	0	801	0	801
12		NAB - Mod/Low	8906	0	12	0.16	70%	55%	0%	6583	10%	658	0	658	39	697
13	Black Warrior Basin	Extention Area	700	0	8	0.16	50%	50%	0%	224	26%	58	0	58	2	60
14		Main Area	1000	3500	12	0.41	70%	100%	0%	2440	100%	2440	744	3184	-205	2979
15	Green River Basin	Shallow	720	17	8	0.41	80%	100%	20%	1507	92%	1386	0	1386	218	1604
16		Deep	3600	0	4	1.20	30%	50%	15%	2203	90%	1983	0	1983	62	2045
17	Piceance Basin	Divide Creek	144	11	8	0.36	50%	100%	13%	179	99%	177	0	177	17	194
18		White River Dome	216	23	8	0.82	88%	100%	8%	1132	99%	1121	0	1121	69	1190
19		Shallow	2000	62	4	0.60	70%	100%	9%	3034	94%	2852	0	2852	-125	2727
20		Deep	2000	0	4	1.20	30%	80%	3%	2235	96%	2145	0	2145	-53	2092
21	Midcontinent Basin	Arkoma	2998	520	8	0.43	66%	100%	0%	6659	70%	4661	0	4661	-550	4111
22		Cherokee & Forest City	2750	0	8	0.13	71%	100%	0%	2031	100%	2031	10	2041	-140	1901
23	Cahaba Basin	Cahaba Basin	387	204	8	0.36	76%	100%	0%	791	100%	791	0	791	-169	622
24	Illinois Basin	Central Basin	1214	4	8	0.24	25%	100%	0%	582	100%	582	0	582	22	604

25	**San Juan Basin**	Northern Basin - CO	780	1091	4	3.04	95%	100%	7%	5450	100%	5450	2871	8321	-3917	4404
26		Fairway- NM	670	434	4	2.32	95%	100%	7%	4604	97%	4466	2568	7034	-2264	4770
27		North Basin - NM	2060	1333	4	0.56	75%	100%	7%	2698	98%	2644	453	3097	2763	5860
28		South Basin - NM	1190	293	4	0.40	75%	100%	7%	1246	100%	1246	117	1363	-53	1310
29		Menefee-NM	7454	0	5	0.19	70%	50%	7%	2305	10%	230	0	230	10	240

Source: Advanced Resources, International

UGRSS MODEL STRUCTURE

<u>INTRODUCTION</u>

The UGRSS was developed offline from EIA=s mainframe OGSM as a standalone model entitled Model of Unconventional Gas Supply (MUGS). It was then programmed as a submodule of the OGSM. A methodology was developed within OGSM to enable it to readily import and manipulate the UGRSS output, which consists essentially of detailed production/reserve/drilling tables disaggregated by the 17 regions within the Natural Gas Transmission and Distribution Module (NGTDM) and by the 6 onshore regions of the OGSM.

The general process flow diagram for the UGRSS is provided in Figure 3B-7. Within each of the 6 Lower-48 State regions, as defined by OGSM; reservoir, cost and technology information were collected to analyze the economics of producing unconventional gas. The UGRSS utilizes price information received from the NGTDM via the OGSM to generate reserve additions and production response based on economic and supply potential.

Figure 3B-7. UGRSS General Process Flow Diagram

Technologies Effect Resource Data, Well Production, Play Availability, and Cost Data Annually

Technology Table Allows Manual Influence of Any Technology Variable

Read Resource Data, Well Recoveries, Reservoir Data

Read Play Resource Profile, Examine Tech. Parameters on Availability/Size of Resource

Determine Size and Availability of the Resource

Read Pricing and Cost Data, Examine Tech. Parameters Effect on Pricing/Costs

Determine Total Cost for Production, Net Price Received, Financial Feasibility of Certain Unconventional Gas Play

If Not

Determine if Play Is or Is Not Profitable

If So

Calculate Wells Drilled, Reserve Additions, R/P, Expected Production and Apply These Statistics to the Next Year

Annual Loop

Annual Loop

Yearly Outputs for Each Unconventional Resource Type Are Apportioned Into NGTDM Regions

Yearly Outputs Are Summed Into A Summary Table

TREATMENT OF ACCESS RESTRICTIONS

A current issue with respect to natural gas development concerns the ability of producers to access natural gas resources on Federal lands. Most of the unconventional gas resources are in the Rocky Mountains, and these resources are subject to a variety of access restrictions. For 5 major basins in the Rocky Mountains an inter-agency assessment of access restrictions was conducted in 2002 by the Federal government under the authority of the Energy Policy and Conservation Act (EPCA)[2]. The access assumptions for the Rocky Mountains in the *Annual Energy Outlook 2007* (AEO2006) reflect the results of the EPCA assessment. In this regard 7 percent of the undeveloped unconventional gas resources are officially off limits to either drilling or surface occupancy. Included in this category are those areas where drilling is precluded by statute (e.g., national parks and wilderness areas) and by administrative decree (e.g., ⱯWilderness Re-inventoried Areas@, ⱯRoadless Areas@). Also included are those areas of a lease where surface occupancy is prohibited by stipulation to protect identified resources such as the habitats of endangered species of plants and animals. An additional 28 percent of the resources are judged to be currently developmentally constrained because of the prohibitive effect of compliance with environmental and pipeline regulations created to effect such laws as the National Historic Preservation Act, the National Environmental Policy Act, the Endangered Species Act, the Air Quality Act, and the Clean Water Act. Approximately 19 percent of the resources are accessible, but located in areas where lease stipulations, which affect accessibility, are set by a federal land management agency, either the U.S. Bureau of Land Management or the U.S. Forest Service. The remaining 46 percent of undeveloped Rocky Mountain unconventional gas resources are located either on Federal land without lease stipulations or on private land and are accessible subject to standard lease terms (i.e., no lease stipulations).

The treatment of access restrictions in the AEO2007 varies by restriction category. Resources that are located on land that is officially inaccessible are removed from the model=s operative resource base. Resources located in areas that are developmentally constrained because of environmental and pipeline regulations are initially removed from the model=s resource base but are made available gradually over the forecast period to reflect the tendency of technological progress to enhance industry=s ability to overcome difficulties in complying with these types of restrictions. Resources that are accessible but located in areas that are subject to lease stipulated access limitations are accounted for by two adjustments. Exploration and development costs are increased by a given amount to reflect the increased costs that these access restrictions generally add to a project. Additionally, time is added to complete a project in these areas to simulate the delay usually incurred as a result of efforts to comply with the access restrictions.

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[2] The following basins (study areas) were reassessed by the USGS as part of a Federal interagency study of access restrictions in the Rocky Mountains: the Paradox/San Juan, the Uinta/Piceance, the Greater Green River, the Powder River, and the Montana Thrust Belt. The study , Scientific Inventory of Onshore Federal Land=s Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development (January 2003) , was conducted under the authority of the Energy Policy and Conservation Act (EPCA).

RESOURCE BASE

Advanced Resources International (ARI) incorporated much of the resource information used in the UGRSS from the 1995 USGS United States Oil and Gas Resource Assessment. ARI also used the NPC and it own studies as reference data to track historical unconventional resource data and to illustrate how the outlook concerning unconventional gas has changed over the last 10 years. After analyzing these studies, ARI chose the specific basins and plays it viewed as important producing or potential unconventional gas areas. Some of these plays included in the UGRSS were not quantitatively assessed in the USGS study. These plays include the deep coalbed methane in the Green River Basin, the Barnett Shale of the Fort Worth Basin, the Fayetteville and Woodford Shales of the Midcontinent Basin and the Tertiary-age and Upper Cretaceous-age tight sands of the Wind River Basin. For these resource estimates, ARI gathered basin and play information from expert sources and added these specific plays to the resource base.

The resource base is established in the first year of the UGRSS and is built upon in each year to produce model outputs. The underlying resource base does not change but it is affected specifically by technology. The static resource base elements and the definitions are presented here:

PNUM	=	Play Number: The play number established by ARI
BASLOC	=	Basin Location: The basin and play name
BASAR	=	Play Area: Area in square miles
DEV_CEL	=	Developed Cells: Number of locations already drilled
WSPAC_CT	=	Well Spacing - Current Technology: Current spacing in acres
WSPAC_AT	=	Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology
SZONE	=	Stimulation Zones: Number of times a single well is stimulated in the play
AVGDPTH	=	Average Depth: Average depth of the play
NOACCESS	=	Percentage of the undrilled locations that are officially inaccessible due to Federal statute or administrative decree (Note: For ΑEPCA≅ plays, plays in basins studied in the EPCA assessment[3], this variable represents only those areas off limits due to Federal statute)

CTUL = Legally accessible undrilled Locations - Current Technology: Current number of locations legally accessible and available to drill

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CTUL = ((BASAR*WSPAC_CT)- (DEV_CEL)) * (1-NOACCESS)

ATUL = Legally accessible undrilled Locations - Advanced Technology: Number of locations legally accessible and available to drill under advanced technology

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ATUL = ((BASAR*WSPAC_AT)- (DEV_CEL)) * (1-NOACCESS)

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[3]Ibid.

WELL PRODUCTIVITY

This section of the unconventional gas model concerns well productivity. The Estimated Ultimate Recovery (EUR) numbers represent ARI modifications of base-level USGS assessments. ARI placed the base case year estimates in as hard-wire figures and then extrapolated these figures throughout the model as formulas. For future years, much of the input resource and production numbers in the UGRSS are derived from equations. Year 1 includes many actual measured values because they offer a base of historic information from which to forecast. Each is noted in this documentation and the actual number and forecast equation are described.

The EUR=s of the potential wells to be drilled in areas that are thought in a given year to be the best 30 percent (in terms of productivity), middle 30 percent, and worst 40 percent, respectively, of a play are based on weighted averages of the true EUR=s for the best 10 percent, next best 20 percent, middle 30 percent, and worst 40 percent of the play. The weights reflect the degree to which the driller is able to ascertain a complete understanding of the play=s structure.

The actual EUR=s for the play in year 1 are represented as follows.

$RW10_1 =$ Reserves per Well for the best 10 percent of the play (year 1): an EUR estimate

$RW20_1 =$ Reserves per Well for the next (lesser) 20 percent of the play (year 1): an EUR estimate

$RW30_1 =$ Reserves per Well for the next (lesser) 30 percent of the play (year 1): an EUR estimate

$RW40_1 =$ Reserves per Well for the worst 40 percent of the play (year 1): an EUR estimate

These EUR's increase over time for all potential wells in all plays as technology progresses in 2 major areas: lower damage completion and stimulation; and improved geology/technology modeling and matching,

$RW10_{iyr} =$ $RW10_{iyr-1}$ * (1 + MINIMUM (REDAM%, (1+REDAM% / DEVPER))
                    + MINIMUM (FRCLEN%,(1+FRCLEN%/DEVPER)))

$RW10_{iyr} =$ $RW10_{iyr-1}$ * (1 + MINIMUM (REDAM%, (1+REDAM% / DEVPER))
                    + MINIMUM (FRCLEN%,(1+FRCLEN%/DEVPER)))

$RW10_{iyr} =$ $RW10_{iyr-1}$ * (1 + MINIMUM (REDAM%, (1+REDAM% / DEVPER))
                    + MINIMUM (FRCLEN%,(1+FRCLEN%/DEVPER)))

$RW10_{iyr} =$ $RW10_{iyr-1}$ * (1 + MINIMUM (REDAM%, (1+REDAM% / DEVPER))
                    + MINIMUM (FRCLEN%,(1+FRCLEN%/DEVPER)))

Where,

REDAM%   =   Total percentage increase over development period due to advances in reduced-damage drilling and stimulation technology

FRCLEN%   =   Total percentage increase over development period due to increase in fracture length from advances in geology/technology modeling matching

DEVPER   =   Total number of years (from base year) over which incremental advances in indicated technology occur

Variables representing the EUR=s of the potential wells to be drilled in a given year are shown below. Note that the EUR=s of all three perceived productivity categories of wells (best 30 percent, middle 30 percent, and worst 40 percent) are equal in the first year. This reflects the relatively random nature of drilling decisions early in the play=s developmental history. As will be shown, these respective EUR=s evolve as information

accumulates and technology advances, enabling drillers to more effectively locate the best prospective areas of the play.

For Year 1:

$MEUR1_{1,1}$ = A weighted average for the EUR values for each (entire) play

$$MEUR1_{1,1} = (0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$$

$MEUR1_{1,2}$ = A weighted average for the perceived best 30 percent of the potential wells in the play

$MEUR1_{1,2}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

$MEUR1_{1,3}$ = A weighted average for the perceived middle 30 percent of the potential wells in the play

$MEUR1_{1,3}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

$MEUR1_{1,4}$ = A weighted average for the perceived worst 40 percent of the potential wells in the play

$MEUR1_{1,4}$ = $(0.10*RW10_1)+(0.20*RW20_1)+(0.30*RW30_1)+(0.40*RW40_1)$

Where,

Subscript 1 = year count, with 1996=1
Subscript 2 = play area
    1 = total area of play
    2 = perceived Abest area@ of the play
    3 = perceived Aaverage area@ of the play
    4 = perceived Aworst area@ of the play

As mentioned above, the equations change for MEUR after the first year. After Year 1, experience and technology enable the play to be better understood geologically and from a potential productive aspect. Accordingly, the model gradually high grades each play into a best, average, and worst area. As the understanding of the play develops over time and technology advances, the area thought to contain the best 30 percent of potential wells from an EUR perspective moves toward an area representative of the actual best 10 percent and 20 percent of wells in the play, the expected average area stays consistent with the middle 30 percent, and the area figured to constitute the worst 40 percent of the potential drilling prospects slowly downgrades to the actual bottom 40 percent

To begin this process, the number of potential wells is first established in year 1 for each perceived productivity category for a given play.

$SCSSRT_1$ = Success Rate : The ratio of successful wells over total wells drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT). Though each of these SCSSRT values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of

		technology on the resource base. These equations will be explained in the technology section.
PLPROB	=	The play probability: Only hypothetical plays have a PLPROB < 100 percent.
PLPROB2	=	The play probability adjusted for technological progress, if initial play probability less than 1
FAC30YR	=	The proportion of the technically recoverable resources that can likely be recovered in the next 30 years - from the USGS
TRW	=	The amount of potential wells available regardless of economic feasibility. Though each of these TRW values is an input value in Year 1, future forecasting turns these inputs into formulas that capture the effects of technology on the resource base. These equations will be explained in the technology section.

$$TRW = (ATUL*SCSSRT*PLPROB2*FAC30YR)$$

Because of the relatively random nature of drilling decisions early in the life of a play, the mix of potential wells by true EUR's in year 1 is the same in each of the 3 perceived productivity categories (areas thought to represent the best 30%, the middle 30%, and the worst 40%, respectively) for a given play. For each perceived productivity category in a given play,

$RW10\_WELLS_1$	=	$.1 * TRW$
$RW20\_WELLS_1$	=	$.2 * TRW$
$RW30\_WELLS_1$	=	$.3 * TRW$
$RW40\_WELLS_1$	=	$.4 * TRW$

Where,

$RW10\_WELLS$=	The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual top 10 percent (by EUR) of the wells in the play
$RW20\_WELLS$=	The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play
$RW30\_WELLS$=	The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play
$RW40\_WELLS$=	The number of available wells in a perceived productivity category that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play

Each successive projection year the mix of potential wells by true EUR (top 10% and 20%, middle 30%, bottom 40%) in each category of perceived EUR (top 30%, middle 30%, and bottom 40%) is adjusted to reflect the increasing ability of producers to better understand the play and also to reflect the removal of wells drilled in the previous year. The actual average EUR for each of the perceived productivity categories is then determined as a well-weighted average of the true EUR's of the wells in the category.

For year greater than 1:

$$\text{MEUR1}_{iyr} = (\text{RW10\_WELLS}_{iyr,}*\text{RW10}_{iyr} + \text{RW20\_WELLS}_{iyr}*\text{RW20}_{iyr} + \text{RW30\_WELLS}_{iyr}*\text{RW30}_{iyr} + \text{RW40\_WELLS}_{iyr}*\text{RW40}_{ute}) / \text{TRW}$$

NEWCAVFRWY	=	For Coalbed Methane, establishes whether or not cavitation technology is advanced to the point that ΛNew Cavity Fairways@ are developed for the plays geologically favorable for use of this technology.
CAVFRWY%	=	For Coalbed Methane, total percentage increase in EUR due to development of New Cavity Fairways.
MEUR2	=	For Coalbed Methane, ΛMEUR1" adjusted for technological progress in the development of New Cavity Fairways (explained in more detail in the Technology Section - Appendix 3-c)

MEUR2 = IF NEWCAVFRWY equal to 1:
MEUR2 = MEUR1 * (1 + CAVFRWY%)
IF NEWCAVFRWY equal to 0:
MEUR2 = MEUR1

ENCBM	=	For Coalbed Methane, establishes whether or not enhanced coalbed methane technologies are available to be used in plays in which such technologies are applicable.
ENCBM%	=	For Enhanced Coalbed Methane, total percentage increase in EUR due to implementation of enhanced coalbed methane technologies.
MEUR3	=	For Enhanced Coalbed Methane, ΛMEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane (explained in more detail in the Technology Section - Appendix 3-c)

MEUR3 = IF ENCBM equal to 1:
MEUR3 = MEUR2 * (1 + ENCBM%)
IF ENCBM not equal to 1:
MEUR3 = MEUR2

| **UNDEV_RES** | = | Undeveloped resources: This formula remains constant throughout the model. |

UNDEV_RES = (MEUR3*TRW)

R_ADD$_{iyr-1}$ =   Total Reserve Additions in the previous year.

RESNPROD$_{iyr}$ =   Beginning-of-year cumulative proved reserves: This is an input number for Year 1 but changes into the following formula for subsequent years.

RESNPROD$_{iyr}$ =   RESNPROD$_{iyr-1}$+R_ADD$_{iyr-1}$

URR   =   Ultimate Recoverable Resources: This formula remains constant throughout the model.

URR   =   (RESNPROD+UNDEV_RES)

ECONOMICS AND PRICING

The next section of the unconventional gas model focuses on economic and pricing of the different types of unconventional gas. The pricing section involves many variables and is impacted by technology.

DIS_FAC   =   Discount Factor: This is the discount factor[4] that is applied to the EUR for each well. The discount factor is based on the Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well over a 20 year period. The stream is discounted at a rate of 15 percent. Both the production stream and the discount rate are variables that are easily modified.

DISCRES   =   Discounted Reserves: The mean EUR per well multiplied by the discount factor.

DISCRES   =   (DIS_FAC*MEUR3)

WHGP   =   Wellhead Gas Price ($/Mcf): The wellhead gas price is received from the NEMS Natural Gas Supply and Disposition Module (NGTDM). It is a market-simulated price solution based on integration of NEMS supply and demand modules.

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[4]The definition for the discount factor is found in the appendix.

BASNDIF   =   Basin Differential: This is asensitivity on the gas price at a basin level. Depending on their proximity to market and infrastructure, the price varies throughout the country. The numbers are constant throughout the model.

ENPVR   =   Expected NPV Revenues: Gives the value of the entire discounted production stream for one well in real dollars.

ENPVR   =   (WHGP+BASNDIF)*DISCRES*1,000,000

DCC_L2K   =   Cost per foot, well is less than 2000 feet.
DCC_G2K   =   Cost per foot, well is greater than 2000 feet.
DCC_G&G   =   Land / G&G Costs
DACC_ADJ   =   Adjustment to calculated drilling costs to reflect proportionate variation in Joint Association Survey (JAS) Drilling Costs in years other than the data year (2002) of the data upon which the equation is based.

DACC   =   Drilling and completion costs

DACC =   IF AVGDPTH less than 2000 feet:
               DACC =   (AVGDPTH*DCC_L2K+DCC_G&G) * DACC_ADJ
               IF AVGDPTH equal to or greater than 2000 feet:
               DACC =   (2000*DCC_L2K+(AVGDEPTH-2000)
                             *DCC_G2K)+DCC_G&G) * DACC_ADJ

The following table represents drilling costs for Coalbed Methane:

Table 3B-6. Drilling Costs ($2002) for Coalbed Methane

Well Depth	Well Cost $2002	Land / G&G Costs $2002
< 2000 feet	$60.00 / foot	$10,000
> 2000 feet	$75.00 / foot	$10,000

Source: Advanced Resources, International

Drilling Costs were calculated by basin for Tight Sands and Gas Shales because of the differing depths among basins and differing state regulations. The formulas for drilling cost equations are similar for tight

sands and gas shales; the average depth of the play is established and at that depth a calculation is made adding a fixed cost to a variable cost per foot.

The following tables represent drilling costs for Tight Sands and Gas Shales:

Table 3B-7. Drilling Costs ($2002) for Tight Sands

UTAH - Uinta Basin			
	Depth	fixed cost	variable cost $/foot
	0-2500	15000	20
	2500-5000	15000	25
	5000-7500	15000	32
	7500-10000	15000	59
	10000-12500	15000	85
	12500-15000	15000	125
	15000-20000	15000	240
WYOMING - Wind River, Greater Green River Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	50
	2500-5000	15000	60
	5000-7500	15000	80
	7500-10000	15000	80
	10000-12500	15000	80
	12500-15000	15000	106
	15000-20000	15000	450
COLORADO - Piceance, Denver Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	20
	2500-5000	15000	25
	5000-7500	15000	32
	7500-10000	15000	59
	10000-12500	15000	85
	12500-15000	15000	125
	15000-20000	15000	200
NEW MEXICO - WEST (Rockies) - San Juan Basin			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	47
	2500-5000	15000	60
	5000-7500	15000	69

Table 3B-7. Drilling Costs ($2002) for Tight Sands

	Depth	fixed cost	variable cost $/ft
	7500-10000	15000	75
	10000-12500	15000	-
	12500-15000	15000	-
	15000-20000	15000	-
NEW MEXICO - East - AZ, SW			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	-
	2500-5000	15000	45
	5000-7500	15000	65
	7500-10000	15000	67
	10000-12500	15000	70
	12500-15000	15000	89
	15000-20000	15000	117
APPALACHIA - Appalachian Basin			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	25
	2500-5000	15000	33
	5000-7500	15000	33
	7500-10000	15000	50
	10000-12500	15000	-
	12500-15000	15000	-
	15000-20000	15000	-
LA/MS/TX Salt Basins - Cotton Valley / Travis Peak			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	25
	2500-5000	15000	32
	5000-7500	15000	59
	7500-10000	15000	85
	10000-12500	15000	125
	12500-15000	15000	200
	15000-20000	15000	-
ARKANSAS/OKLAHOMA/TEXAS - Arkoma / Anadarko Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	63
	2500-5000	15000	65

Table 3B-7. Drilling Costs ($2002) for Tight Sands

	Depth	fixed cost	variable cost $/ft
	5000-7500	15000	70
	7500-10000	15000	83
	10000-12500	15000	112
	12500-15000	15000	150
	15000-20000	15000	200
MONTANA - Northern Great Plains Basins			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	34
	2500-5000	15000	34
	5000-7500	15000	-
	7500-10000	15000	-
	10000-12500	15000	-
	12500-15000	15000	-
	15000-20000	15000	-
TX - Texas Gulf Basins -- Wilcox/Lobo, Vicksburg, Olmos			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	25
	2500-5000	15000	50
	5000-7500	15000	74
	7500-10000	15000	105
	10000-12500	15000	160
	12500-15000	15000	217
	15000-20000	15000	300
TX / NM - Permian Basin -- Canyon Sands			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	0
	2500-5000	15000	45
	5000-7500	15000	65
	7500-10000	15000	67
	10000-12500	15000	70
	12500-15000	15000	89
	15000-20000	15000	117
TX / NM - Permian Basin -- Abo			
	Depth	fixed cost	variable cost $/ft

Table 3B-7. Drilling Costs ($2002) for Tight Sands

	0-2500	15000	0
	2500-5000	15000	78
	5000-7500	15000	90
	7500-10000	15000	100
	10000-12500	15000	115
	12500-15000	15000	150
	15000-20000	15000	200

Source: Advanced Resources, International

Table 3B- 8. Drilling Costs ($2002) for Gas Shales

MI - Antrim Shale Wells			
	Depth	fixed cost	variable cost $/ft
	0-2500	15000	80
	2500-5000	15000	100
	5000-7500	15000	120
	7500-10000	15000	130
	10000-12500	15000	130
	12500-15000	15000	130
	15000-20000	15000	130

Source: Advanced Resources, International

STIM_CST   =   Variable average cost of stimulating one zone. (Number of zones is a variable)

STIMC   =   Stimulation Costs: Provides the cost of stimulating a well in the specific basin by multiplying the given average stimulation cost by the number of stimulation zones.

STIMC   =   (SZONE*STM_CST)

BASET	=	Variable cost of Pumping and Surface equipment when H_2O disposal is required.
WATR_DISP	=	Establishes whether or not (and degree to which) water disposal is required (No Disposal=0; Maximum Disposal=1)
PASE	=	Pumping and Surface Equipment Costs: Determines if the play requires H_2O disposal, adds the variable pumping and surface equipment cost, and multiplies the average depth (if so) to the variable tubing cost of $1 / foot. If not, a flat variable is added.

PASE	=	IF WATR_DISP is equal to 1:
		PASE $=$ BASET + AVGDPTH
		IF WATR_DISP is not equal to 1:
		PASE $=$ 10000.

WOMS_LE	=	Small Well Lease Equipment Costs
WOMM_LE	=	Medium Well Lease Equipment Costs
WOML_LE	=	Large Well Lease Equipment Costs
WOML_WTR	=	Water Producing Well Lease Equipment Costs
LSE_EQ_ADJ	=	Adjustment to calculated lease equipment costs to reflect proportionate variation in Energy Information Administration lease equipment costs in years other than the data year (2002) of the data upon which the equation is based.
LSE_EQ	=	Lease Equipment Costs: For tight gas and gas shale it is first established whether H2O disposal is needed and, if so, a fee is added to the variable Lease Equipment costs depending on MEUR. For coalbed methane a base level lease equipment costs is used, which cost varies by play. These input values are multiplied by LSE_EQ_ADJ.

The matrix for Lease Equipment costs and EUR is shown below:

Table 3B-9. Lease Equipment Costs ($2002) Matrix

Well Size (EUR)	Reservoir Type	Lease Equipment	Water
Well Size O&M Small Well - <0.5 Bcf	Tight Sands – Rocky Mountain	$ 155,274	$ -
	Tight Sands – Non Rocky Mountain	$ 77,637	$ -
	Gas Shales	$ 38,819	$ 11,091
Well O&M Medium Well - <2.0 Bcf	Tight Sands – Rocky Mountain	$ 199,638	$ -
	Tight Sands – Non Rocky Mountain	$ 99,819	$ -
	Gas Shales	$ 49,910	$ 22,182
Well O&M Large Well - >2.0 Bcf	Tight Sands – Rocky Mountain	$ 288,366	$ -
	Tight Sands – Non Rocky Mountain	$ 144,183	$ -
	Gas Shales	$ 72,092	$ 33,273

Source: Non Rocky Mountain: Advanced Resources, International; Rocky Mountain: Leo Giangiacomo

LSE_EQ	=	LSE_EQ * LSE_EQ_ADJ

RST = Percent variable G&A Cost - Currently 10 percent

GAA10 = G&A Costs: Adds on a variable G&A cost

GAA10= RST*(LSE_EQ+ PASE+ STIMC+ DACC)

TCC = Total Capital Costs: The sum of Stimulation Costs, Pumping and Surface Equipment Costs, Lease Equipment Costs, G&A Costs and Drilling and Completion Costs

TCC = DACC+STIMC+PASE+LSE_EQ+GAA10

DHC = Dry Hole Costs: Calculates the dry hole costs

DHC	=	(DACC+STIMC) * ((1/SCSSRT)-1)

LEASSTIP	=	Lease Stipulated Share: The percentage of the play that is subject to Federal lease stipulations
ACC_COST	=	The extra cost in Federal restricted areas (areas subject to Federal lease stipulations)
CCWDH	=	Capital Costs & Dry Hole Costs with Access Adjustment: Combines these two costs, converts into $/Mcf, and adjusts costs to reflect higher costs in portion of play where lease stipulations occur

CCWDH	=	If ACCESS equals 0 or YEAR is less than ACCESS_YR:
		CCWDH = (LEASSTIP/(1.0-NOACCESS))*(1.0+ACC_COST)*((TCC+DHC)/DISCRES*1,000,000)) + ((1.0-LEASSTIP-NOACCESS)/ (1.0-NOACCESS))*((TCC+DHC)/DISCRES*1,000,000)
		If ACCESS is not equal to 0 and YEAR is greater than or equal to ACCESS_YR:
		CCWDH = (TCC+DHC)/(DISCRES*1,000,000

GASTR	=	Gas treatment costs ($/Mcf)

GASTR	=	If Tight Sands:
		GASTR = .125 + WHGP/32.0
		If Gas Shales:
		GASTR = .125 + WHGP/32.0
		If Coalbed Methane:
		GASTR = .25 + WHGP/16.0

WTR_DSPT	=	Water Disposal Fee: $0.05 per Mcf
WDT%	=	Total percentage decrease in H_2O disposal and treatment costs over the development period due to technological advances [There was no change in these costs in the AEO2007]
WOMS	=	H_2O Costs, Small Well [Equals 0 in the AEO2007]
PUMP%	=	Total percentage decrease in pumping costs over the development period due to technological advances [There was no change in these costs in the AEO2007]

TECHYRS = Number of years (from base year) over which incremental advances in indicated technology have occurred

GTF% = Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances [There was no change in these costs in the AEO2007]

VOC = Variable Operating Costs: Establishes if the play requires H_2O disposal and adds the appropriate cost ($/Mcf)

VOC = IF WATR_DISP is equal to 1:
VOC = (WTR_DSPT*(TECHYRS)*(WDT%/30))
+((WOMS)*(TECHYRS)*(PUMP%/30))
+((GASTR)*(TECHYRS)*(GTF%/30))
+(WTR_DSPT+WOMS+GASTR)
IF WATR_DISP is equal to 0:
VOC = (WTR_DSPT*(TECHYRS)*(WDT%/30))
+((WOMS)*(TECHYRS)*(PUMP%/30))
+((GASTR)*(TECHYRS)*(GTF%/30))
+(WOMS+GASTR)

ECBM_OC = Enhanced CBM Operating Costs Variable - $2.00 ($2002) per Mcf
ENH_CBM% = Enhanced CBM EUR Percentage gain

VOC2 = Variable Operating Costs: Establishes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future

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VOC2 = If ECBMR is equal to 1:
VOC2 = (VOC+((ECBM_OC+VOC)*(ENH_CBM%))/
(1+ENH_CBM%))
If ECBMR is not equal to 1:
VOC2 = VOC

WOMS_OMW = Operating & Maintenance - Small well with H_2O disposal
WOMM_OMW = Operating & Maintenance - Medium well with H_2O disposal
WOML_OMW = Operating & Maintenance - Large well with H_2O disposal
WOMS_OM = Operating & Maintenance - Small well without H_2O disposal
WOMM_OM = Operating & Maintenance - Medium well without H_2O disposal
WOML_OM = Operating & Maintenance - Large well without H_2O disposal
FOMC_ADJ = Adjustment to calculated fixed operating and maintenance costs to reflect proportionate variation in Energy Information

Administration operating costs in years other than the data year (2002) of the data upon which the equation is based.

FOMC = Fixed Operating and Maintenance Costs. For Tight Sands and Gas Shales: (1) Establish whether or not the play requires H2O disposal; (2) determine the size of the reserves / well (EUR); (3) calculate the Fixed O&M Costs for the well. For coalbed methane a base level fixed operating and maintenance cost is used, which cost varies by play. These input values are multiplied by FOMC_ADJ.

Table 3B-10. Operation and Maintenance Costs ($2002) Matrix: Tight Sands and Gas Shales

OGSM Region	Well Size (EUR)	Well O&M H_2O	Well O&M No H_2O
Northeast	<0.5 Bcf	$ 226560	$ 147264
	<2.0 Bcf	$ 283680	$ 184392
	>2.0 Bcf	$ 434880	$ 282672
Gulf Coast	<0.5 Bcf	$ 179328	$ 119612
	<2.0 Bcf	$ 279360	$ 186333
	>2.0 Bcf	$ 371520	$ 247804
Mid-continent	<0.5 Bcf	$ 226560	$ 151116
	<2.0 Bcf	$ 283680	$ 189215
	>2.0 Bcf	$ 434880	$ 290065
Southwest	<0.5 Bcf	$ 195017	$ 130076
	<2.0 Bcf	$ 272320	$ 181637
	>2.0 Bcf	$ 378720	$ 252606
Rocky Mountain	<0.5 Bcf	$ 231040	$ 154104
	<2.0 Bcf	$ 268160	$ 178863
	>2.0 Bcf	$ 401280	$ 267654
West Coast	<0.5 Bcf	$ 231040	$ 154104
	<2.0 Bcf	$ 268160	$ 178863
	>2.0 Bcf	$ 401280	$ 267654

Source: Advanced Resources, International

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Tight Sands and Gas Shales

FOMC = If WATR_DISP is greater than or equal to 0.5:

      If MEUR3 is less than or equal to .5:

      FOMC = (DIS_FACT*WOMS_OMW
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

      If MEUR3 is greater than .5 and less than or equal to 2:

      FOMC = (DIS_FACT*WOMM_OMW
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

      If MEUR3 is greater than 2:

      FOMC = (DIS_FACT*WOML_OMS
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

If WATR_DISP is less than 0.5:

      If MEUR3 is less than or equal to .5:

      FOMC = (.6*DIS_FACT*WOMS_OMW
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

      If MEUR3 is greater than .5 and less than or equal to 2:

      FOMC = (.6*DIS_FACT*WOMM_OMW
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

      If MEUR3 is greater than 2:

      FOMC = (.6*DIS_FACT*WOML_OMS
              +VOC2*(DISCRES*1,000,000))
              *FOMC_ADJ

</div>

TOTL_CST = Total Costs ($/Mcf): Calculates the total costs of producing the gas in ($/Mcf)

<div style="border:1px solid black">

TOTL_CST = CCWDH+FOMC/(DISCRES*1,000,000)

</div>

    ROYALTY = Royalty (14.6% for Rocky Mountain plays, 12.5% for all other plays)
    SEVTAX = Severance Tax (play-level input)

    NET_PRC = Net Price ($/Mcf): Calculates the Royalty & Severance Tax on the gas price

<div style="border:1px solid black">

NET_PRC = (1-ROYALTY-SEVTAX)*(WHGP+BASNDIF)

</div>

<u>NET PROFITABILITY</u>

The next section of the unconventional gas model focuses on profitability. The profitability of the play drives the model outputs. The better the economics of the play, the faster it will be developed so that the operator will maximize the potential economic profit.

MIN_ROI   =   Risk premium ($/Mcf): A minimum rate of return on investment

NET_PROF   =   Net Profits ($/Mcf): Calculates whether or not the play is profitable under the current variable conditions

NET_PROF   =   NET_PRC - TOTL_CST - MIN_ROI

<u>MODEL OUTPUTS</u>

The last section of the unconventional gas model supplies the user with yearly model outputs by play.

ENPRGS	=	Establishes if the play is pipeline or environmentally regulated.
ENV%	=	The percentage of the play that is not restricted from development due to environmental or pipeline regulations
LOW%	=	The percentage of the play that is restricted from development due to environmental or pipeline regulations
LOWYRS	=	The number of years that it will take for technology improvements to offset the prohibitive effect of the environmental and or pipeline regulations.

UNDV_WELLS = Undeveloped Wells: (1) establish whether or not prohibitive environmental or pipeline regulations exist for the play (Note: For EPCA plays this step applies only to environmental regulation.) (3) If such regulations exist, restrict a certain percentage of the play from development; (4) If such regulations do not exist, allow the entire play to be accessible for development.

UNDV_WELLS	=	If ENPRGS	=	1:	
		UNDV_WELLS	=	TRW*(ENV%+ (LOW%/LOWYRS) *TECHYRS)	
		If ENPRGS	=	0:	
		UNDV_WELLS	=	TRW	

EPCA	=	Establishes if a play is in a basin that was studied in the EPCA assessment (in studied basin = 1, not in studied basin = 0)
NACC_FA	=	For EPCA plays - the percentage of the play that is off limits due to Federal administrative decree.

UNDV_WELLS2 = For EPCA plays - available wells adjusted to account for well locations that are off limits due to Federal administrative decree.

UNDV_WELLS2	=	If EPCA is equal to 1:		
		UNDV_WELLS2	=	(1. - NACC_FA) * UNDV_WELLS
		If EPCA is equal to 0:		
		UNDV_WELLS2	=	UNDV_WELLS

NACC_PIPE	=	For EPCA plays - the percentage of the play that is initially off limits due to pipeline regulations.
LIFRT_PIPE	=	For EPCA plays - the percentage of the play that is initially off limits due to pipeline regulations, the amount in percentage that will become accessible each year due to technological progress (e.g., if 23 percent is initially off limits and LIFRT_PIPE = 1 percent, then 1 of this 23 percent will become accessible each year due to technological progress).

UNDV_WELLS3 = For EPCA plays - available wells adjusted to account for well locations that are off limits due to pipeline regulations.

UNDV_WELLS3 = If EPCA is equal to 1:
UNDV_WELLS3 = minimum (1.,
(1.-NACC_PIPE+LIFRT_PIPE*TECHYRS)) *
UNDV_WELLS2
If EPCA is equal to 0::
UNDV_WELLS3 = UNDV_WELLS2

NORM	=	The Standard Normal Density Function NORM(X) = ((1./((2.*3.14159265)**.5))*exp(-.5*X**2)
CNORM	=	The Standard Normal Cumulative Distribution Function CNORM(X) = 1. – NORM(X) * (.31938*(1./(1.+.23164*X)) - .35656*((1/(1+.23164*X))**2.) + 1.78147*((1./(1.+.23164*X))**3.) - 1.82125*((1./(1.+.23164*X))**4.) + 1.33027*((1./(1.+.23164*X))**5.) e.g,, CNORM(1.96) =.975.
C1	=	Common (to all plays) constant in estimated function for FOR_WELLS_RATIO
B1	=	Binary constant (specific to a given play) in estimated function for FOR_WELLS_RATIO
B2, B3, B4	=	Coefficients on explanatory variables in estimated function for FOR_WELLS_RATIO
SIGMA	=	Parameter in estimated function for FOR_WELLS_RATIO

FOR_WELLS_RATIO = The share of total accessible wells (UNDEV_WELLS3) drilled in

a given year

FOR_WELLS_RATIO= NORM((MAX(0.0,C1+B1+B2*CUM_RAT
+B3*NET_PROF+B4*US_ED)/ SIGMA))
* SIGMA
+
CNORM((MAX(0.0,C1+B1+B2*CUM_RAT
+B3*NET_PROF+B4*US_ED)/ SIGMA)) *
(MAX(0.0,C1+B1+B2*CUM_RAT+B3*NET_PROF+B4*
US_ED)

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NW_WELLS   =   New Wells: The number of discovery wells drilled in the current year

NW_WELLS =   If HYPPLAYS equals 0:
                                If NET_PROF is greater than or equal to 0.0:
                                NW_WELLS = FOR_WELLS_RATIO*UNDEV_WELLS3
                                If NET_PROF is less than 0:
                                        If NET_PROF is greater than or equal to -1.0:
                                        NW_WELLS=.75*FOR_WELLS_RATIO*
                                            UNDEV_WELLS3
                                        If NET_PROF is less than -1.0 and greater than or
                                        Equal to -2.0:
                                        NW_WELLS   =.5*FOR_WELLS_RATIO*
                                            UNDEV_WELLS3
                                        If NET_PROF is less than -2.0:
                                        NW_WELLS   =   0.0
                        If HYPPLAYS equal 1:
                        NW_WELLS=0.0

EMERGBAS   =   The parameter that determines if the play is an emerging play.
                                This designation was made by ARI.
EMERG%   =   The number of years added onto the drilling schedule because of the
                                hindrance of the play being an emerging play.
EMERG#   =   The number of ⌐emerging play≥ additional years taken off the drilling
                                schedule by advancements in technology.

NW_WELLS2 =   New Wells: This variable adjusts the new wells in a play to reflect that
the

                                play is an emerging play

NW_WELLS2   =   If EMERGBAS is equal to 1:
                                NW_WELLS2 = NW_WELLS*
                                                        ((UNDEV_WELLS3/NW_WELLS2)/
                                                        ((UNDEV_WELLS3/NW_WELLS2)+
                                                        EMERG%-EMERG#)
                                If EMERGBAS is equal to 0:
                                NW_WELLS2 = NW_WELLS

ACC_XYRS% =   The percentage increase in the number of years it takes to develop a
                                play in Federal restricted areas (areas subject to Federal lease
stipulations)

NW_WELLS3 =   New wells: This variable adjusts the new wells for the play to reflect
                                the effect of access-limiting lease stipulations

| NW_WELLS3 | = | If ACCESS equals 0 or YEAR is less than ACCESS_YR:
NW_WELLS3 = NW_WELLS2 *
$\quad$ 1 / ((1.0+LEASSTIP*ACC_XYRS%)/
$\quad$ (1.0-NOACCESS))
If ACCESS is not equal to 0 and year is greater than or
equal to ACCESS_YR:
NW_WELLS3 = NW_WELLS2 |

NW_WELLS_LAG $\quad$ = $\quad$ New Wells Lagged: The number of discovery wells drilled in the play in the previous year

NW_WELLS4 = $\quad$ New wells: This variable constricts the new discovery wells to be within a reasonable range of variation from year-to-year

| **NW_WELLS4** = | If UNDEV_WELLS3 is greater than NW_WELLS3:
$\quad$ If NW_WELLS_LAG is greater than 0.0:
$\quad\quad$ If NW_WELLS3 is greater than
$\quad\quad\quad$ 1.3*NW_WELLS_LAG:
$\quad\quad$ NW_WELLS4 = 1.3*NW_WELLS_LAG
$\quad\quad$ If NW_WELLS3 is less than
$\quad\quad\quad$ .7*NW_WELLS_LAG:
$\quad\quad$ NW_WELLS4 =.7*NW_WELLS_LAG
$\quad$ If NW_WELLS_LAG equals 0.0:
$\quad$ NW_WELLS4 = .5*NW_WELLS3
If UNDEV_WELLS3 is less than or equal to NW_WELLS3:
NW_WELLS4 = UNDEV_WELLS3 |

NW_RGA% $\quad$ = $\quad$ For new well, as a share of ultimate reserve additions, that portion not booked in the current year but appearing in future years as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

DRA $\quad$ = $\quad$ Drilled Reserve Additions: Reserve additions booked in the current year and resulting directly from new wells drilled in the current year.

| DRA | = | NW_WELLS4*MEUR4*(1-NW_RGA%) |

NW_INFRES $\quad$ = $\quad$ For new wells, the total amount of reserve additions that will be booked after the current year as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

NW_INFRES	=	NEWWELLS4*MEUR4*NW_RGA%

PROV_RES = Beginning-of-Year Proved Reserves for the current year: This variable is a plugged number in the first year to equate with the EIA published figure

RES_GR = Establishes for a given play whether or not initial reserves (reserves existing in year 1) will have reserve growth. These parameters are explained in the technology section.

RGR_IR = Reserve Growth Rate of initial reserves.

RGRADD_IR = Reserve Growth Additions from initial reserves: This variable establishes if the play will have reserve growth for reserves existing in Year 1 and then allocates an appropriate amount for the play

RGRADD_IR = If RES_GR is equal to 1:
       If ENCBM is equal to 1:
       $RGA\_IR = RGR*PROV\_RES_1 + .025*((MEUR3-MEUR2)*DEV\_CEL)$
       If ENCBM is not equal to 1:
       $RGA\_IR = RGR*PROV\_RES_1:$
    If RES_GR is not equal to 1:
    RGA_IR = 0

NW_INFRES = For a new well, the total amount of reserve additions that will be booked in future years as reserve growth additions resulting from workovers, re-fracturing, technological enhancements, etc.

NW_INFRES	=	NEWWELLS4*MEUR4*NW_RGA%

RGR_NR = Reserve Growth Rate of reserves added in Year 1 through the Preceding year.

RGADD_NR = Reserve Growth Additions from reserves added after Year 1.

RGRADD_NR	=	$RGR\_NR*(DRA_1.......DRA_{iyr-1})$

R_ADD = Total Reserve Additions: This variable sums the Drilled Reserves and Reserve Growth.

R_ADD	=	DRA+RGRADD_IR+RGRADD_NR

PROD = Current (realized) Production: This variable is a plugged number in historical years. In projection years it is received from the NEMS NGTDM.

PROV_RES2 = Beginning-of-Year Proved Reserves for the next year: This variable calculates the reserves for the coming year from the calculation of occurrences during the year.

PROV_RES2 =	If (PROV_RES+R_ADD-PROD) is greater than 0:
	PROV_RES2 = PROV_RES+R_ADD-PROD
	If (PROV_RES+R_ADD-PROD) is less than or equal to 0:
	PROV_RES2 = 0

RP_RAT = Reserves-to-Production (R/P) Ratio: This variable is the current R/P ratio. For some plays this is a plugged number in the first year.

C_PR = Constant in auto-regressive estimation of the logistical transformation of the production-to-reserve (P/R) ratio

RHO = Autoregressive parameter in auto-regressive estimation of the logistical transformation of the P/R ratio

B1_PR, B2_PR,B3_PR = Estimated coefficients on explanatory variables in auto-regressive estimation of the logistical transformation of the P/R ratio

RA_RATIO = Ratio of reserve additions (R_ADD) in current year to beginning-of-year Reserves (PROV_RES) in current year

RA_RATIO_LAG = Ratio of reserve additions in previous year to beginning-of-year reserves in previous year

LOGISTIC_PR_LAG = The previous year's value for the logistical transformation of the P/R ratio

LOGISTIC_PR = The estimated logistical transformation of the P/R ratio.

LOGISTIC_PR =	If R_ADD and PROV_RES are not equal to 0:
	LOGISTIC_PR = C_RP*(1.-RHO)+B1_RP*RA_RATIO
	+B2_RP*RA_RATIO_LAG
	+B3_RP*NW_WELLS4
	+ RHO*LOGISTIC_PR_LAG
	+ RHO*(B1_RP*RA_RATIO_LAG
	+B2_RP*RA_RATIO_LAG2
	+B3_RP*NW_WELLS_LAG)

MIN_RP	=	Minimum achievable R/P ratio

RP_RAT2 = R/P Ratio for the next year: This variable establishes the expected play-level R/P ratio for the next projection year.

RP_RAT2 = If R_ADD and PROV_RES are not equal to 0:
RP_RAT2 = 1./(exponential(LOGISTIC_PR)/
(1.+exponential(LOGISTIC_PR))
If R_ADD or PROV_RES is equal to 0:
If RP_RAT is greater than MIN_RP:
RP_RAT2 = RP_RAT –
(1.0-Minimum(1.0,R_ADD/PROD))
If RP_RAT is less than or equal to MIN_RP:
If (MIN_RP-RP_RAT) is less than 1.0:
RP_RAT2 = RP_RAT+1.0
If (MIN_RP-RP_RAT) is equal to or less than 1.0:
RP_RAT2 = MIN_RP

PROD2 = Expected (not realized) production for the following year: This variable is combined with other OGSM expected production values to obtain expected NGTDM regional-level Production-to-Reserve ratios for the following year.

PROD2 = If RP_RAT2 is equal to 0:
PROD2 = 0
If RP_RAT2 is not equal to 0:
PROD2 = PROV_RES2/(RP_RAT2)

UNDV_WELLS4 = Remaining potential discovery wells available for drilling in following years.

UNDV_WELLS4 = If ENPRGS is equal to 1:
UNDV_WELLS4 = TRW-NW_WELLS4
If ENPRGS is not equal to 1:
If UNDV_WELLS3 is equal to 0:
UNDV_WELLS4 = 0.0
If UNDV_WELLS3 is not equal to 0:
If(UNDV_WELLS3-NW_WELLS4) is
equal to 0.0:
UNDV_WELLS4 = 0.1
If (UNDV_WELLS3-NW_WELLS4) is not
equal to 0.0:
UNDV_WELLS4 = maximum(0.0,
UNDV_WELLS3
- NW_WELLS4)

In the following section the mix of potential discovery wells by true EUR (top 10% and 20%, middle 30%, bottom 40%) in each category of perceived EUR (top 30%, middle 30%, and bottom 40%) for the following year is adjusted to reflect the increasing ability of producers to better understand the play and to reflect the removal of wells drilled in the current year.

For each perceived productivity category:

RW10_NEWWELLS = The number of new wells drilled that have an EUR equal to the average EUR for the actual top 10 percent (by EUR) of the wells in the play

RW20_NEWWELLS = The number of new wells drilled that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play

RW30_NEWWELLS = The number of new wells drilled that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play

RW40_NEWWELLS = The number of new wells drilled that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play

$$\text{RW10\_NEWWELLS} = \text{NW\_WELLS4} * (\text{RW10\_WELLS}/(\text{RW10\_WELLS} + \text{RW20\_WELLS} + \text{RW30\_WELLS} + \text{RW40\_WELLS}))$$

$$\text{RW20\_NEWWELLS} = \text{NW\_WELLS4} * (\text{RW20\_WELLS}/(\text{RW10\_WELLS} + \text{RW20\_WELLS} + \text{RW30\_WELLS} + \text{RW40\_WELLS}))$$

$$\text{RW30\_NEWWELLS} = \text{NW\_WELLS4} * (\text{RW30\_WELLS}/(\text{RW10\_WELLS} + \text{RW20\_WELLS} + \text{RW30\_WELLS} + \text{RW40\_WELLS}))$$

$$\text{RW40\_NEWWELLS} = \text{NW\_WELLS4} * (\text{RW40\_WELLS}/(\text{RW10\_WELLS} + \text{RW20\_WELLS} + \text{RW30\_WELLS} + \text{RW40\_WELLS}))$$

TOT_RW10_WELLS = The total number of remaining wells (adjusted for new wells drilled) in the play that have an EUR equal to the average EUR for the original top 10 percent (in Year 1) of the wells in the play

TOT_RW20_WELLS = The total number of remaining wells in the play that have an EUR equal to the average EUR for the original next highest 20 percent of the wells in the play

TOT_RW30_WELLS = The total number of remaining wells in the play that have an EUR equal

		to the average EUR for the original next highest 30 percent of the wells in the play
TOT_RW40_WELLS	=	The total number of remaining wells in the play that have an EUR equal to the average EUR for the original lowest 40 percent of the wells in the play
SHIFT%	=	A factor representing the effect of accumulated information and advancing technology that enables drillers to more effectively locate the best prospective areas of the play.
$RW10\_WELLS_{iyr+1}$	=	For the following year, the number of available wells that have an EUR equal to the average EUR for the actual top10 percent of the wells in the play
$RW20\_WELLS_{iry+1}$	=	For the following year, the number of available wells that have an EUR equal to the average EUR for the actual next highest 20 percent of the wells in the play
$RW30\_WELLS_{iyr+1}$	=	For the following year, the number of available wells that have an EUR equal to the average EUR for the actual next highest ("middle") 30 percent of the wells in the play
$RW40\_WELLS_{iyr+1}$	=	For the following year, the number of available wells that have an EUR equal to the average EUR for the actual lowest 40 percent of the wells in the play

For play area thought to be the top 30 percent with respect to productivity:

$$RW10\_WELLS_{iyr+1} = TOT\_RW10\_WELLS*minimum(.3+SHIFT\%,1.0)$$

$$RW20\_WELLS_{iyr+1} = TOT\_RW20\_WELLS_{iyr}*minimum(.3+SHIFT\%,1.0)$$

$$RW30\_WELLS_{iyr+1} = TOT\_RW30\_WELLS_{iyr}*maximum(.3-(3/7)*SHIFT\%,0.0)$$

$$RW40\_WELLS_{iyr+1} = TOT\_RW40\_WELLS_{iyr}*maximum(.3-(1/2)*SHIFT\%,0.0)$$

For play area thought to be the middle 30 percent with respect to productivity:

$$RW10\_WELLS_{iyr+1} = TOT\_RW10\_WELLS*maximum(.3-(3/7)*SHIFT\%,0.0)$$

$$RW20\_WELLS_{iyr+1} = TOT\_RW20\_WELLS*maximum(.3-(3/7)*SHIFT\%,0.0)$$

$$\boxed{RW30\_WELLS_{iyr+1} \quad = \quad TOT\_RW30\_WELLS*minimum(.3+SHIFT\%),1.0)}$$

$$\boxed{RW40\_WELLS_{iyr+1} \quad = \quad TOT\_RW40\_WELLS*maximum(.3-((1/2)*SHIFT\%),0.0)}$$

For play area thought to be the lowest 40 percent with respect to productivity:

$$\boxed{RW10\_WELLS_{iyr+1} \quad = \quad TOT\_RW10\_WELLS*maximum(.4-(4/7)*SHIFT\%,0.0)}$$

$$\boxed{RW20\_WELLS_{iyr+1} \quad = \quad TOT\_RW20\_WELLS*maximum(.4-(4/7)*SHIFT\%,0.0)}$$

$$\boxed{RW30\_WELLS_{iyr+1} \quad = \quad TOT\_RW30\_WELLS*maximum(.4-(4/7)*SHIFT\%,0.0)}$$

$$\boxed{RW40\_WELLS_{iyr+1} \quad = \quad TOT\_RW40\_WELLS*minimum(.4-(1/2)*SHIFT\%,0.0)}$$

WELLON% = The proportion of the year that a well drilled in the current year is in production

PROD1STYR%= The proportion of a well=s total production stream that occurs in the first full year of production

INFILL_WELLS = The number of infill wells drilled as implied by the expected production for the following year

$$\boxed{\begin{array}{lll} \textbf{INFILL\_WELLS} & = & Max(0, (PROD2-(1-(1/RP\_RAT))*PROD) \\ & & /(WELLON\%*PROD1STYR\%*MEUR4) \\ & & \textbf{-} NW\_WELLS2) \end{array}}$$

TOT_WELLS_LAG = The total successful wells drilled in the previous year

TOT_WELLS =   The total successful wells drilled in the current year

TOT_WELLS =   If(NW_WELLS4+INFILL_WELLS) is greater than
         1.3*TOT_WELLS_LAG:
TOT_WELLS =   1.3*(NW_WELLS4+INFILL_WELLS)
Else if TOT_WELLS is less than .7*(NW_WELLS4
         +INFILL_WELLS)
TOT_WELLS =   .7*(NW_WELLS4+INFILL_WELLS)
Else:
TOT_WELLS =   NW_WELLS4+INFILL_WELLS

Appendix 3C. Unconventional Gas Recovery Supply Technologies

INTRODUCTION

The Unconventional Gas Recovery Supply Submodule (UGRSS), shown in **Figure 3C-1**, relies on the Technology Impacts and Timing functions to capture the effects of technology progress on the costs and rates of gas production from coalbed methane, gas shales, and tight sands. The numerous types of research and technologies are grouped into 11 specific Atechnology packages@ that encompass the full spectrum of key disciplines -- geology, engineering, operations, and the environment. The enclosed materials define these 11 technology packages for unconventional gas exploration and production (E&P).

The technology packages are grouped into four distinct technology cases -- Reference Case, Slow Technology, and Rapid Technology -- that capture three different futures for technology progress, as further described below:

    X   **Reference Case** captures the current status and trends in the E&P technology for unconventional gas. In addition to industry funded R&D, a limited amount of R&D on tight sand reservoirs is directly supported by the U.S. Department of Energy (DOE), particularly on advanced macro-exploration, seismic technologies, and matching of technology to reservoir settings. The Gas Technology Institute (GTI) R&D program funds valuable studies of emerging and future gas plays and supports advanced well stimulation technology. Also, direct R&D on coalbed methane (CBM) has been funded by the DOE Small Business Innovative Research (SBIR) program for CBM cavitation technology. In addition to the directly funded R&D, considerable indirect R&D by DOE, GTI and industry contributes to unconventional gas E&P, particularly on drilling cost reductions, re-stimulation opportunities, produced gas and water treatment, and environmental mitigation. However, overall technology progress in unconventional gas has slowed noticeably with the phase-out of formal R&D on this topic by GTI and the United States Geological Survey (USGS).

    X   For the Annual Energy Outlook 2008 (AEO2008), the **Slow Technology** case represents an R&D outlook where the effects of the various technologies are generally about 50 percent less than in the Reference Case.

    X   For the AEO2008, the **Rapid Technology** case represents an R&D outlook where the effects of the various technologies are generally about 50 percent greater than in the Reference Case.

Figure 3C-1

NEMS Unconventional Gas Recovery Supply Submodule

- 1. Resource Base and Productivity
- 2. Initial Drilling, Production and Reserves
- 3. Costs and Economics
- 4. Technology Impacts and Timing
- 5. Drilling and Capital Allocation
- 6. Production, Reserve Additions and Reserves Accounting

INTEGRATED FORECASTS OF SUPPLY, PRICES AND BENEFITS
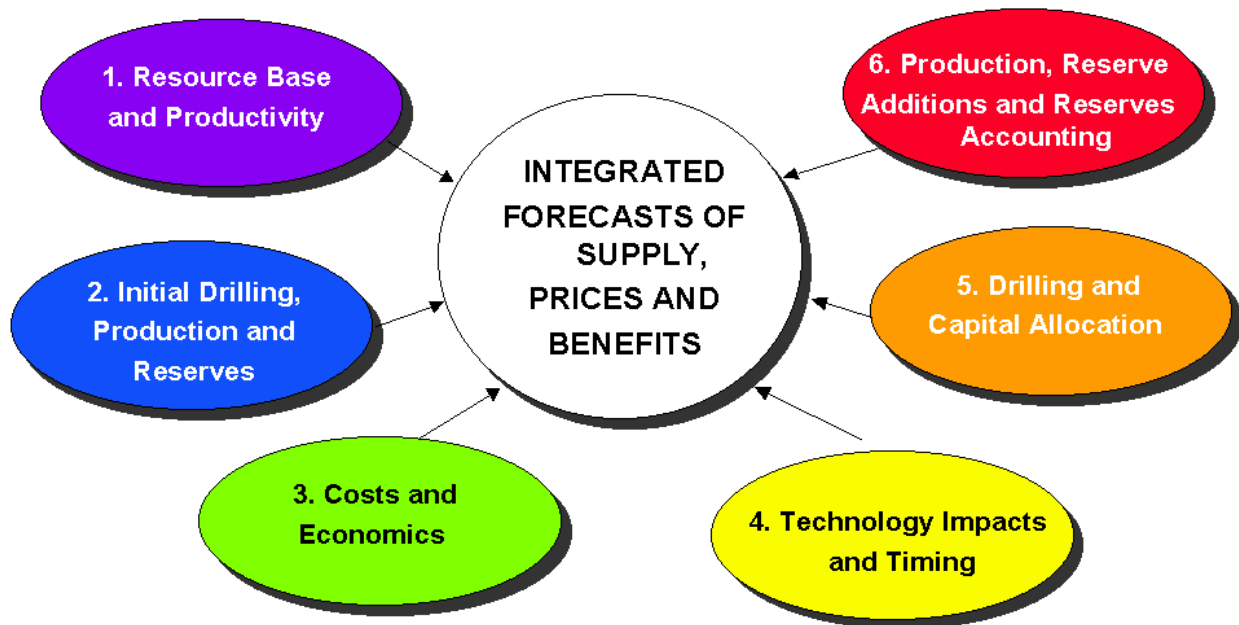
The 11 high impact technology packages addressed by the UGRSS are listed below:

1. Increasing the Resource Base with Basin Assessments.

2. Accelerating the Development of Emerging Plays and Expanding the Resource Base with Play Specific, Extended Reservoir Characterization.

3. Improving Reserve Growth in Existing Fields with Advanced Well Performance Diagnostics and Remediation.

4. Improving Exploration Efficiency with Advanced Exploration and Natural Fracture Detection R&D.

5. Increasing Reserves Per Well with Geology/Technology Modeling and Matching.

6. Improving Well Performance with More Effective, Lower Damage Well Completions and Stimulations.

7. Lowering Well Drilling and Completion Costs with Targeted Drilling and Hydraulic Fracturing R&D.

8. Lowering Water Disposal and Gas Treating Costs by using New Practices and Technology.

9. Improving Recovery Efficiencies with Advanced Well Completion Technologies such as Cavitation, Horizontal Drilling and Multi-Lateral Wells.

10. Improving and Accelerating Gas Production with Other Unconventional Gas Technologies, such as Enhanced CBM and Gas Shales Recovery.

11. Mitigating Environmental and Other Constraints that Severely Restrict Development.

The impact each of these 11 R&D packages has on unconventional gas development and the specific Αtechnology lever@ used to model these impacts in the Supply and Technology Model is shown on **Table 3C-1**.

Table 3C-1

Summary of Technological Progress

R&D Program	General Impact	Specific Technology Lever
1. Basin Assessments	Increases available resource base	Accelerates time hypothetical plays become available for development
2. Extended Resource Characterization	Increases pace of new development	Accelerates pace of development for emerging plays
3. Well Performance Diagnostics and Remediation	Expands resource base	Extends reserve growth for already proved reserves
4. Exploration and Natural Fracture Detection R&D	Increases success of development	Improves exploration/development success rate for all plays
	Improves exploration efficiency	Improves ability to find best prospects and areas
5. Geology/Technology Modeling & Matching	Matches ⒶBest Available Technology@ to play	Improves EURs/Well
6. Improved Drilling and Completion Technology	Improves fracture length and conductivity	Improves EURs/Well
	Reduces drilling and stimulation damage	Improves R/P ratios
7. Lower Cost Drilling and Stimulation	More efficient drilling and stimulation	Lowers well drilling and stimulation capital costs
8. Lower Cost Water and Gas Treating	More efficient gas separation and water	Lowers water and gas treatment Operation and Maintenance (O&M) costs

9. Advanced Well Completion	Defines applicable plays	Accelerates date technology is available
	Introduces improved version of technology	Increases recovery efficiency
10. Other Recovery Technology	Introduces dramatically new recovery technology	Accelerates date technology is available
		Increases EURs/Well and lowers costs
11. Environmental Mitigation	Removes development constraints in environmentally sensitive basins	Increases basin areas available for for development

The detailed parameter values and expected impacts for each technology case are provided on **Table 3C-2** for Coalbed Methane (CBM), on **Table 3C-3** for gas shales, and **Table 3C-4** for Tight Gas Sands.

The remainder of the enclosed materials describe for each technology area: (1) the technical problem(s) currently constraining unconventional gas development; (2) the technology solutions and R&D program being proposed; and, (3) the expected impact and benefits from successful development and implementation of R&D.

Table 3C-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted	Technology Lever	Current Situation	Technology Cases		
				Reference Case	Slow Technology	Rapid Technology
1. Basin Assessment	Hypothetical Plays	Date Available	Not Available	Not Available	Not Available	Not Available
2. Extended Resource Characterization	Emerging Plays	Pace of Development	30 to 60 years (+30 years over Developing Plays)	1.0 yr/year (Max - 30 years)	0.5 yr/year (Max - 30 years)	1.5 yr/year (Max - 30 years)
3. Well Performance Diagnostics & Remediation	Proved Reserves	Reserve Growth	All Plays with Proved Reserves @ 3%/yr., declining	All Plays @ 2%/yr., declining .1% over 40 years	All Plays @ 1%/yr., declining .1% over 20 years	All Plays @ 3%/yr., declining .1% over 60 years
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	+.2%/year from 2005 (max 95%)	+.1%/year from 2005 (max 95%)	+.3%/year from 2005 (max 95%)
		b. Exploration Efficiency	Random	Identify ᴀBest@ 30% by Year 2045	Identify ᴀBest@ 30% by year 2100	Identify ᴀBest@ 30% by year 2031
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.2%/year (30 years)	+.1%/year (30 years)	+.3%/year (30 years)
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+.36%/year (30 years)	+.18%/year (30 years)	+.45%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-.25%/year (30 years)	-.13%/year (30 years)	-.38%/year (30 years)
8. Water and Gas Treating R&D	Wet CBM Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	Not Available	Not Available	Not Available
9. Advanced CBM Cavitation	Cavity Fairway Plays	EUR/Well	As Calculated	Not Available	Not Available	2016
10. Enhanced CBM Recovery	ECBM Eligible Plays	a. Recovery/ Efficiency	As Calculated	+20%	Not Available	+30%
		b. O&M Costs/Mcf	As Calculated	+$1.00($1996)/ Mcf, Incremental	Not Available	+$0.75($1996)/ Mcf, Incremental

Table 3C-2
Details of Coalbed Methane Technological Progress

R&D Program	CBM Resource Impacted	Technology Lever	Current Situation	Technology Cases		
				Reference Case	Slow Technology	Rapid Technology
11. Environmental Mitigation	EV Sensitive Plays	c. Year Available	Not Available	2025	Not Available	2015
		Acreage Available	Non- EPCA[1]: 35% of Play Restricted	Non-EPCA Plays: Removed in 35 years (0.7%/year)	Non-EPCA Plays: Removed in 70 years (0.35%/year)	Non-EPCA Plays: Removed in 23 years (1.05%/year)
			EPCA Plays: Variable	EPCA Plays: Variable	EPCA Plays: Variable (.5*Reference Case Values)	EPCA Plays: Variable (1.5*Reference Case Values)

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[1] The following basins (study areas) were reassessed by the USGS as part of a Federal interagency study of access restrictions in the Rocky Mountains: the Paradox/San Juan, the Uinta/Piceance, the Greater Green River, the Powder River, and the Montana Thrust Belt. The study , *Scientific Inventory of Onshore Federal Land=s Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development* (January 2003) , was conducted under the authority of the Energy Policy and Conservation Act (EPCA).

Table 3C-3
Details of Gas Shales Technological Progress

R&D Program	Gas Shales Resource Impacted	Technology Lever	Current Situation	Technology Cases		
				Reference Case	Slow Technology	Rapid Technology
1. Basin Assessment	Hypothet-ical Plays	Date Available	Not Available	Not Available	Not Available	Not Available
2. Extended Resource Characterization	Emerging Plays	Pace of Development	30 to 60 years (+30 years over Developing Plays)	1.0 yr/year (Max -30 years)	0.5 yr/year (Max - 30 years)	1.5 yrs/year (Max -30 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	All Plays with Proved Reserves @ 3%/yr., declining	All Plays @ 4%/yr., declining .1% over 40 years	All Plays @ 2%/yr., declining .1% over 20 years	All Plays 6%/yr, declining .1% over 60 years
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	25% to 95%	+.2%/year from 2005 (max 95%)	+.1%/year from 2005 (max 95%)	+.3%/year from 2005 (max 95%)
		b. Exploration Efficiency	Random	Identify ⱯBest@ 30% by Year 2045	Identify ⱯBest@ 30% by year 2100	Identify ⱯBest@ 30% by year 2031
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.25%/year (30 years)	+.13%/year (30 years)	+.38%/year (30 years)
6. Improved Drilling and Stimulation	All Plays	EUR/Well	As Calculated	+.25%/year (30 years)	+.13%/year (30 years)	+.38%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	Not Available	Not Available	Not Available
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.30/Mcf	Not Available	Not Available	Not Available
9. Multi-Lateral Completions	Eligible Plays	Recovery Efficiency	As Calculated	20% (Year 2016)	Not Available	30% (Year 2009)
10. Other Gas Shales Technology	Eligible Plays	a. EUR/Well	As Calculated	Not Available	Not Available	Not Available
		b. O&M Costs/Mcf	As Calculated	Not Available	Not Available	Not Available
		c. Year Available	Not Available	Not Available	Not Available	Not Available
11. Environ-mental Mitigation	EV Sensitive Plays	Acreage Available	35% of Play Restricted	Removed in 35 years (1%/year)	Removed in 70 years (.5%/ year)	Removed in 23 years (1.5%/year)

Table 3C-4
Details of Tight Gas Sands Technological Progress

R&D Program	Tight Sands Resource Impacted	Technology Lever	Current Situation	Technology Cases		
				Reference Case	Slow Technology	Rapid Technology
1. Basin Assessment	Hypothetical Plays	a. Date Available	Not Available	2021	2021	2021
2. Extended Resource Characterization	Emerging Plays	Pace of Development	30 to 60 years (+20 years over Developing Plays)	-.75 yr/year (Max -30 years)	-.38 yr/year (Max -30 years)	-1.13 yr/year (Max -30 years)
3. Well Performance Diagnostics and Remediation	Proved Reserves	Reserve Growth	San Juan Basin @ 3%/yr., declining	All Plays @ 1%/yr., declining (20 years)	All Plays @ 0.5%/yr., declining (10 years)	All Plays 1.5%/yr, declining (30 years)
4. Exploration & Natural Fracture Detection R&D	All Plays	a. E/D Success Rate	30% to 95%	+.2%/year from 2005 (max 95%)	+.1%/year from 2005 (max 95%)	+.3%/year from 2005 (max 95%)
		b. Exploration Efficiency	Random	Identify ABest@ 30% by Year 2045	Identify ABest@ 30% by year 2100	Identify ABest@ 30% by year 2031
5. Geology/ Technology Modeling and Matching	All Plays	EUR/Well	As Calculated	+.20%/year (30 years)	+.10% (30 years)	+.30% (30 years)
6. Improved Drilling and Stimulation	All Plays	a. EUR/Well	As Calculated	+.36%/year (30 years)	+.18%/year (30 years)	+.45%/year (30 years)
7. Lower Cost Drilling & Stimulation	All Plays	D&S Costs/Well	As Calculated	-0.13%/year (30 years)	-0.25%/year (30 years)	-0.38%/year (30 years)
8. Water and Gas Treating R&D	All Plays	Water & Gas Treating O&M Costs/Mcf	$0.15/Mcf	Not Available	Not Available	Not Available

Table 3C-4
Details of Tight Gas Sands Technological Progress

R&D Program	Tight Sands Resource Impacted	Technology Lever	Current Situation	Technology Cases		
				Reference Case	Slow Technology	Rapid Technology
9. Horizontal Wells	Continuous Sands	Recovery Efficiency	As Calculated	+20% (year 2025)	Not Available	+30% (year 2015)
10. Other Tight Sands Technology	Eligible Plays	a. EUR/Well	As Calculated	Not Available	Not Available	Not Available
		b. O&M Costs/Mcf	As Calculated	Not Available	Not Available	Not Available
		c. Year Available	Not Available	Not Available	Not Available	Not Available
11. Environmental Mitigation	EV Sensitive Plays	Acreage Available	Non-EPCA Plays: 35% of Play Restricted	Non-EPCA Plays: Removed in 35 years (0.7%/year)	Non-EPCA Plays: Removed in 70 years (.35%/ year)	Non-EPCA Plays: Removed in 23 years (1.05%/year)
			EPCA Plays: Variable	EPCA Plays: Variable	EPCA Plays: Variable: .5*Reference Case Values	EPCA Plays: Variable: 1.5*Reference Case Values

Technology Packages

1. Increasing the Resource Base with Basin Assessments

Background and Problem
A significant portion of the unconventional gas resource base (54 Tcf) and many of the high potential gas settings are hypothetical plays. Because basic information is lacking on these plays, industry is constrained in exploring or developing them in a timely fashion. The hypothetical plays listed on **Tables 3C-5**, **3C-6**, and **3C-7** are currently not available for development. The 1995 USGS National Assessment was used as the basis for the play categorization and for guidance on resource estimates in these tables. In addition, the resource estimates for certain of the plays have been updated and expanded by special studies by Advanced Resources International, Inc.

Technology Lever
Fundamental studies of the geology and hydrocarbon potential of these new gas plays will be required to initiate their development. These studies would provide the essential foundation for exploring and developing natural gas from hypothetical plays and would improve their probabilities for success.

Foundation for Technology Lever
The foundation for the ΑBasin Studies and Assessments@ technology lever is expert judgment. The input data for this expert judgment stems from the observed industry responses to a variety of major basin level studies of unconventional gas prepared in the past 25 years:

$ Initial ERDA/DOE basin and play level resource and recoverable estimates for tight gas basins (1980).
$ Subsequent Gas Resource Institute (GRI) series of basin studies and assessments for eight major coalbed methane basins (1990-1997), prepared by ARI and the Bureau of Economic Geology (BEG), Texas.
$ Joint USGS/ARI basin study and assessment for the Barnett Shale in the Fort Worth Basin, Texas (1998).
$ ΑPortfolio of Emerging Natural Gas Resources@ (1999) for the three major Rocky Mountain tight gas basins, sponsored by GRI and prepared by ARI.
$ Gas Atlas series for major natural gas producing states or regions, sponsored by GRI and prepared by BEG, Barlow and Haun and various state geological surveys.

Table 3C-5

<u>Hypothetical CBM Plays and Resources</u>

Basins	Gas Plays	Undeveloped Resource (Bcf)
Appalachia	N. Basin – Moderate/Low	1,384
San Juan	Southern (Menefee)	239
Uinta	Sego	376
Piceance	Deep Basin	2,239*
Green River	Deep Basin	547*
Black Warrior	Extention Area	60

Source: Advanced Resources, International

New Deep CBM plays added by Advanced Resources International, Inc.

Table 3C-6

Hypothetical Gas Shale Plays and Resources

Basin	Gas Play	Undeveloped Resources (Bcf)
Appalachia	Appalachia – Low Thermal Maturity	4,086
Michigan	Antrim Shale -Undeveloped Area	7,921
Illinois	New Albany Shale - Developing Area	2,026
Cincinnati Arch	Devonian Shale	738
Williston	Shallow Niobrara - Biogenic Gas	3,832

Source: Advanced Resources, International

Table 3C-7

Hypothetical Tight Sand Plays and Resources

Basin	Gas Plays	Undeveloped Resources (Bcf)
Columbia	Basin Center	479
Uinta	Deep Synclinal MV	2,152
Greater Green River	Deep Mesaverde	5,452
	Deep Frontier	10,956
Wind River	Fort Union/Lance Deep	9,976*
Williston	Moderate Potential	1,227
	Low Potential	680

Source: Advanced Resources, International

New Tight Gas Plays added by Advanced Resources International, Inc.

9

2. Accelerating the Development of Emerging Unconventional Gas Plays With Reservoir Characterization

Background and Problem

Much of the unconventional gas resource (about 95 Tcf) is in new, emerging plays in the Rocky Mountain basins. Reliable, rigorous information on the key reservoir parameters controlling the gas production in these new, poorly defined gas plays is lacking. Also lacking is information on how best to match technology to the geology and reservoir properties of these gas plays. Because of this lack of information, industry assigns a higher risk when evaluating these basins and plays and proceeds slowly during their initial development.

Technology Lever

Performing extended, three-dimensional reservoir characterization studies of emerging plays, partnering with industry in Awells of opportunity,@ sponsoring rigorously evaluated technology and geology/reservoir tests, and providing proactive technology transfer would help define and disseminate essential information of high value to the E&P industry on the Aemerging@ gas plays.

Impacts and Benefits

The gas plays listed on **Tables 3C-8, 3C-9 and 3C-10** are categorized as Aemerging@ for CBM, gas shales, and tight sands. These plays currently entail higher risks and a slower pace of development, estimated as a 30 year Astretch-out@ in field development time.

Foundation for Technology Lever

The foundation for the APlay-Specific Resource Characterization@ technology lever is based on the observed industry response to a series of DOE and GRI sponsored field R&D and reservoir characterization studies in unconventional gas plays:

$ DOE=s MWX field laboratory at Rulison Field, Piceance Basin, Colorado provided detailed information on the deposition continuity and properties of the lenticular Williams Fork/Mesaverde tight gas sands. Before R&D, lenticular sands were considered undevelopable. Today, the Rulison Field and the Williams Fork Formation is a multi-Tcf natural gas play.

$ GRI=s reservoir characterization of the Barnett Shale at Newark Field provided essential information that has led to nearly 2,000 wells being drilled in this new very active gas shale play.

$ Extensive resource characterization of Warrior Basin coalbed methane, at GRI=s Rock Creek Field Laboratory, assisted this basin to provide the first active CBM play in the country.

Table 3C-8

Emerging CBM Plays and Resources

Basin	Gas Play	Undeveloped Resources (Bcf)
Appalachia	Northern Basin-High Thermal Maturity	2,474
Illinois	Central Basin	597
Uinta	Blackhawk Formation	590
Piceance	White River Dome	2,438
	Shallow	3,256
Raton	Northern Basin	1,586
Greater Green River	Washakie	1,281
Powder River	Central Basin	7,305
	Wasatch	129

Source: Advanced Resources, International

Table 3C-9

<u>Emerging Gas Shale Plays and Resources</u>

Basin	Gas Plays	Undeveloped Resources (Bcf)
Appalachia	Devonian Shale - Big Sandy Extension Area	3,403
	Devonian Shale - Greater Siltstone Area	1,824

Source: Advanced Resources, International

Table 3C-10

Emerging Tight Sand Plays and Resources

Basins	Gas Plays	Undeveloped Resources (Bcf)
Texas Gulf Coast	Olmos	3,540*
Wind River	Ft. Union/Lance Shallow	10,747*
	Mesaverde/Frontier Shallow	1,099*
	Mesaverde/Frontier Deep	2,267
Greater Green River	Ft. Union/Fox Hills/Lance	29,404
	Lewis	14,103
	Shallow Mesaverde (2)	10,711
Piceance	N. Basin Williams Fork /Mesaverde	936
	Iles/Mesaverde	603
Uinta	Basin Flank Mesaverde	3,263
	Tertiary West	1,460
Williston	High Potential	2,808
Midcontinent	Anadarko – Granite Wash/Atoka	3,301
Appalachia	Berea Sandstone	11,478
	Upper Devonian High	6,905
	Upper Devonian Moderate-Low	6,612
	Tuscarora Sandstone	2,501
	Clinton/Medina Moderate-Low	479

Source: Advanced Resources, International

New Tight Gas plays added by Advanced Resources International, Inc.

3. Extending Reserve Growth in Existing Unconventional Gas Fields with Advanced Well Performance Diagnostics and Remediation

Background and Problem

A review of the historical data shows that proved reserves in existing unconventional gas fields grow by 2 to 4 percent per year due to adjustments and revisions stemming from uphole well recompletions, restimulation and more effective production practices. However, the pace of this non-drilling based reserve growth has been declining steadily as operators face increasing difficulties in identifying and diagnosing the problems of low recovery efficiencies and underperforming unconventional gas wells.

Technology Lever

A rigorous unconventional gas well diagnostics and remediation R&D program would provide the appropriate set of tools for evaluating and targeting problem gas wells. It would also provide a basis for designing and selecting the appropriate cost-effective well remediation technologies, helping support continued reserve growth.

Impact and Benefits

The gas plays listed on **Tables 3C-11, 3C-12 and 3C-13** are existing unconventional plays with advanced well performance diagnostics and remediation.

Foundation for Technology Lever

The foundation for the A   Reserve Growth@ technology lever is data from a select number of basins and areas where unconventional gas dominates natural gas production, such as W. New Mexico (with its extensive tight gas and CBM plays), Utah (also with tight gas and CBM plays), and Michigan (with its Antrim Shale gas play). These data series show that proved reserves grow at annual rate of 2% to 4% due to non-drilling based activities such as adjustments and revisions, depending on the basin and gas play, as discussed below:

$ The tight gas in the E. Texas Basin (Texas Railroad District (TRR) #6) has had 509 Bcf of growth on original reserves of 5.9 Tcf or about 2% per year.

$ The combined tight gas and coalbed methane play in the San Juan Basin (W. New Mexico) has had 1,845 Bcf of growth on original reserves of 13.7 Tcf or about 3% per year.

$ The newer CBM and tight gas play in the Uinta Basin (Utah) and the shale gas plays in the Michigan and the Fort Worth basins (TRR #9) have seen reserve growth of 15% to 20% per year but may not be representative of the largest set of unconventional gas plays.

Table 3C-11

CBM Plays With Proved Reserves

Basin	Gas Play	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
San Juan	North Basin (CO)	696	700
	Cavity Fairway (NM)	6,170	6,157
	North Basin (NM)	586	550
	South Basin (NM)	152	150
Warrior	Main Area	972	823
Uinta	Ferron Formation	400	400
Raton	North Basin Area	0	31
	Purgatory River Area	100	249
Powder River	Wyodak Upper Ft. Union	100	150
Piceance	Divide Creek	56	52
Appalachia	Central Basin	1,137	1,172
Mid Continent	Arkoma	200	220
	Cherokee & Forest City	13	13
TOTALS		**10,582**	**10,667**

Source: Advanced Resources, International

Table 3C-12

Gas Shale Plays With Proved Reserves

Basins	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Devonian Shale - Big Sandy Central Area	1,122	1,137
	Devonian Shale - Big Sandy Extension Area	281	255
Michigan	Antrim Shale - Developing Area	1,005	1615
Fort Worth*	Barnett Shale - Core Area	208	270
TOTALS		**2,616**	**3,277**

Source: Advanced Resources, International

*New Gas Shale plays added by Advanced Resources International, Inc

.

Table 3C-13

Tight Sand Plays With Proved Reserves

Basin	Gas Plays	Proved Reserves (Bcf) 1/96	Proved Reserves (Bcf) 1/97
Appalachia	Clinton/Medina High	815	961
	Upper Devonian High	3,262	3,484
San Juan	Picture Cliffs	900	960
	Central Basin/Mesaverde	5,200	5,200
	Central Basin/Dakota	2,700	2,600
Uinta	Tertiary East	500	500
	Basin Flank MV	10	9
Piceance	S. Basin Williams Fork/Mesaverde	600	700
	Iles/Mesaverde	150	140
Green River	Ft. Union/Fox Hills/Lance	100	500
	Lewis	200	200
	Shallow Mesaverde(1)	1,800	1,900
	Deep MV	70	70
	Frontier (Moxa Arch)	1,800	1,600
	Frontier (Deep)	10	0
Wind River	Ft. Union/Lance Shallow	300	700
	Mesaverde/Frontier Shallow	300	250
Denver	Denver Jules - All Tight Gas	1,000	1,050
LA/Mississippi Salt	East Texas - Cotton Valley/Bossier	4,200	4,000
Texas Gulf Coast	Vicksburg	1,750	2,030
	Wilcox/Lobo	2,700	2,900
	Olmos	300	400
Permian	Canyon	1,600	1,600
	Abo	1,200	1,100
Anadarko	Cleveland	300	300
	Cherokee/Redfork	1,400	1,400
	Granite Wash/ Atoka	200	200
Williston	High Potential	300	700
Arkoma	Atoka	700	600
	TOTALS	**34,407**	**36,004**

Source: Advanced Resources, International

4. Improving Exploration Efficiency with Advanced Exploration and Natural Fracture Detection Technology

Background and Problem

In settings where the unconventional gas resource has sufficiently high gas concentration and is intensely naturally fractured, this resource can be produced at commercial rates. Finding these settings of high natural fracture intensity and diversity of orientation is a major technical challenge and greatly influences the economics of unconventional gas development. Since the productive areas in undeveloped plays are often difficult to identify, unconventional gas developers can drill a large number of ʌeconomically dry@ wells with reserves of 0.1 Bcf per well or less. Because of these high numbers of dry and ʌeconomically dry@ wells, the development success rates for new unconventional gas plays typically range from 50 to 90%.

Technology Lever

The R&D goal is to develop and demonstrate improved exploration technology to enable producers to find the best (ʌsweet spot@) portions of these gas basins and to improve their success rates. Sweet spots are zones in generally tight reservoirs that produce commercial quantities of oil or gas mostly due to interconnecting natural fractures. The fractures can be due to tectonic movement, and the locations and orientations of the fractures can often be estimated by understanding the local tectonic stresses and applying data analysis and modeling. The quality of a sweet spot depends on the interaction of several attributes, including fracture porosity, location along migration pathways, favorable facies and a good regional pressure seal above the target horizon.

Impacts and Benefits

This technology addresses the question of exploration efficiency, the ʌc@ factor in the exploration efficiency equation, and enables the industry to find the ʌbest 30 percent@ of the basin by the year the assumed year.

Foundation for Technology Lever

The basic assumption is that with trial and error drilling, industry would eventually establish the higher productivity portions of a play without new technology. The development and application of natural fracture and advanced logging technology enables this ʌhigh grading@ process to occur sooner. The current industry capacity to ʌhigh grade@ basin areas is illustrated in Attachment A by the still limited ability to identify higher productivity areas in the Drunkard=s Wash CBM play in the Uinta Basin (Case Study 3).

The foundation for the ʌExploration Efficiency@ technology lever is based on the initial field demonstration of DOE-sponsored natural fracture detection R&D and improved logging technology in the southern Piceance Basin which provided an improved ability to high grade the potential drilling sites in the southern portion of the Rulison Field, as discussed in Attachment A (Case Study 1)..

5. Increasing Recovery Efficiency With Geology/Technology Modeling and Matching

Background and Problem

Field development plans and operations are challenging to design for unconventional gas plays, given the complex, difficult to measure and widely varying reservoir properties. As a result, the selection and application of Abest available@ technology and production practices to optimize gas recovery has proven to be difficult. Fields are often developed with a variety of assumptions and Arules of thumb@ about reservoir properties and technology performance, without consideration of the complex interaction of the reservoir and the chosen technology. This leads to much lower than optimum gas recoveries per well.

Technology Lever

The key task is improved understanding of unconventional gas reservoir conditions and appraisals of Abest available@ technology. For this, new research data on low resistivity sands, stress sensitive formations, and natural fracture patterns are essential. Also needed are advanced reservoir simulators that can properly model these complex settings and behaviors, and thus provide more reliable projections of gas recovery. These data and tools would allow more optimum selection of appropriate technology for efficient field development

Impacts and Benefits

This technology increases recovery from new wells.

Foundation for Technology Lever

The Individual case studies in Attachment A show a steady improvement in reserves per well with increased understanding of the geologic setting and the appropriate set of technologies for optimizing gas recovery from these deposits. The assumption is that this improvement continues, but at a slower pace than in the past due to reduced R&D investments in geology and technology matching.

6. Improving Well Performance With Lower Damage, More Effective Well Completions and Stimulations

Background and Problem

The permeability in CBM, gas shale and tight sand formations is easily damaged by use of chemicals, gels, drilling muds and heavy cement, leading to underperforming wells. Improving well drilling, completion and stimulation fluids and procedures would help improve recoveries from such wells, particularly in multi-zone, vertically heterogeneous formations.

Technology Lever

R&D on formation and fluid compatibility, low damage fluids such as CO_2 or N_2, improved rock mechanics and stimulation models, underbalanced drilling, and improved proppant carrying fluids, particularly for multi-zone reservoirs, could reduce formation damage, increase fracture length and placement, and increase fracture conductivity, thus improving reserves per well

Impacts and Benefits

All unconventional gas plays, because of their low permeability, would benefit from improved well completion and stimulation.

Foundation for Technology Lever

The Case studies in Attachment A show a steady improvement in reserves per well with introduction of lower damage, more effective well completion and stimulation technology. The assumption is that this improvement continues, but at a slower pace than in the past due to reduced R&D investments in advanced, multi-zone well completions technology and appropriate, non-damaging well stimulation technology.

7. Lowering Well Drilling and Completion Costs with Unconventional Gas Specific Drilling and Hydraulic Fracturing R&D

Background and Problem
Well drilling and completion represent the primary capital cost items in unconventional gas development and place a high economic hurdle on these resources, particularly when these costs are assessed using discounted cash flow analysis. Lowering well drilling and stimulation costs would significantly improve the overall economics, particularly for the deeper, low permeability gas plays.

Technology Lever
R&D on advanced drilling and completion methods, particularly the use of downhole motors and modified stimulation practices, will lead to faster formation penetration rates, simpler frac fluids, and thus lower costs.

Impacts and Benefits
Well drilling and completion costs are reduced, in real terms.

Foundation for Technology Lever
Natural gas well costs, after declining from the mid-1980s to the mid-1990's, reversed course and have climbed significantly in the past five years, as shown below:

Table 3C-14

Natural Gas Well Drilling and Completion Costs

Year	Average Nominal Costs		Adjusted for Drilling Activity And Inflation (01 dollars)	
	Per Well	Per Foot	Per Well	Per Foot
1995	630	96	540	104
1996	622	98	566	109
1997	723	115	624	120
1998	816	128	676	131
1999	766	132	665	129
2000	684	125	661	128

Source: Advanced Resources, International

Using the activity and inflation adjusted data, natural gas well costs between 1995 and 2000 increased by $121,000 per well (22%) between 1995 to 1999 (@ 4% per year) and by $24 per foot (23%) in the 2000. Approximately, one-half of this increase has been in the rig day-rate and the other one-half has been due to higher fuel costs and adjustments from depressed mid-1990's costs.

With rig day-rates close to replacement costs (at least for the new HP flex-rigs), we expect that continued

improvements in drilling efficiencies (due to the modest level of investment in technology), will counter increases in drilling costs (in real dollars) in future years. Without investment in R&D, well costs would increase by 2% per year (in real dollars).

8. Lowering Water Disposal and Gas Treating Costs Through New Practices and Technologies

Background and Problem
Disposing the produced water and treating the produced methane for CO_2 and N_2 contaminants add significant costs to unconventional gas operations. Lowering these costs would improve the overall economics of the gas plays, particularly those with high water production and CO_2 content.

Technology Lever
R&D on water treatment, such as the use of electrodialysis and reverse osmosis, and improved water disposal practices, may lead to lower produced water disposal costs. R&D on gas treating, such as the use of advanced membranes, may help lower the costs of CO_2 and N_2 removal.

Impacts and Benefits
O&M costs remain flat, in real terms, in all 3 technology cases.

Foundation for Technology Lever
Natural gas well operating costs, after declining from the mid-1980s to the mid-1990s, reversed course and have increased in between 1995 and 1999, as shown below:

Table 3C-15

Natural Gas Well Operating Costs Indices

Year	Inflation Adjusted Gas Recovery Operating Cost Index
1995	90.7
1996	90.9
1997	95.3
1998	98.1
1999	97.6
2000	n/a

Source: Advanced Resources, International

Using the above operating cost index data, natural gas operating costs rose by 6.9 index points (7.6% in four years) or 2% per year.

We estimate that investment in gas and water treatment technology will counter increases in gas and water treatment O&M costs (in real dollars) in future years. Without investment in R&D, gas and water treatment costs would increase by 2% per year (in real dollars).

9. Improving Recovery Efficiency With Advanced Well Drilling and Completion Technology

Background and Problem

Horizontal wells in geologically-appropriate "blanket type@ tight sand formations provide improved reservoir contact and, theoretically, considerably improved recovery efficiencies and reserves per well. However, the performance of horizontal wells in tight sands has been disappointing to date, raising concerns about drilling damage and selection of geologically appropriate settings. For example, DOE supported horizontal wells at the MWX site in the Southern Piceance Basin and at Table Rock in the Eastern Greater Green River Basin turned to water after high initial gas rates.

Cavitation of CBM wells in geologically favorable Acavity fairways@ provides gas production rates, reserves and recovery efficiencies far in excess of traditionally drilled, cased and hydraulically stimulated wells. However, little is known on what combination of reservoir properties is essential or favorable for cavitation, and little has been invested in cavitation science, design or operating procedures. As a result, only one Acavity fairway@ has been established in the U.S. to date -- in the central San Juan Basin.

Because gas shales generally have a thick pay section, multiple productive horizons, and low vertical permeability, horizontal wells may not be a technology of choice. However, the use of multiple laterals may enable a single vertical wellbore to contact and efficiently drain a vertically thick, heterogeneous gas shale formation.

Technology Lever

Additional horizontal, multi-lateral and cavitation well R&D may help define the appropriate geologic settings for using this technology, particularly in damage sensitive, low permeability formations. DOE=s R&D, including its participation in the SBIR program provides a modest level of investigation on these topics.

Impact and Benefits

The unconventional gas plays listed in **Table 3C-16** are potentially favorable for advanced well D&C technology.

Table 3C-16

**Unconventional Gas Plays Applicable
for Advanced Well Drilling and Completion Technologies**

Basin	Gas Play
Tight Sands	
Appalachia	Clinton/Medina High
Denver	Denver Jules - All Tight Gas
Greater Green River	Shallow Mesaverde (2)
	Frontier (Deep)
Piceance	Iles/Mesaverde
San Juan	Central Basin/Dakota
Coalbed Methane	
San Juan	Fairway (NM) (existing)
Uinta	Ferron
Raton	Purgatory River
Piceance	Shallow Coals
Green River	Washakie
Gas Shales	
Michigan	Antrim, Developing Area
	Antrim, Undeveloped Area
Illinois	New Albany, Developing Area
Williston	Shallow Niobrara

Foundation for Technology Lever

The foundation for the AAdvanced Drilling and Completion@ technology lever is documented improvements in well performance reserves per well that have resulted from:

$ Application of horizontal well drilling in Ablanket@ tight gas sand formations such as the Frontier Formation at Table Rock, Greater Green River Basin and several other settings.

$ Application of cavity completion technology in the coalbed methane Afairway@ of the San Juan Basin.

$ Application of horizontal well drilling, with stimulation in the core area of the Barnett Shale in the Fort Worth Basin.

10. Improving and Accelerating Gas Production With Other (ᴀBreakthrough@) Unconventional Gas Technologies

Background and Problem

A variety of longer-term and advanced ᴀbreakthrough@ technologies could further improve the performance of unconventional gas plays and wells. For example, laboratory tests demonstrate that injection of adsorbing gases such as CO_2 and N_2 into coal seams and other unconventional gas formations can improve and accelerate the desorption and production of natural gas. However, major questions remain as to how the injected gases will flow in the reservoir, how effectively these injected gases will contact and displace methane adsorbed on the coals, and how to cost-efficiently treat the produced methane/injected gas mixtures. All basins and gas plays are potentially candidates for breakthrough technologies.

Technology Lever

A fundamental and comprehensive R&D program involving geologic, laboratory, and field studies of enhanced unconventional gas recovery (similar to those underway for enhanced oil recovery) would provide industry the basic information on the feasibility of and appropriate settings for potential breakthrough technologies.

Foundation for Technology Lever

The foundation for the ᴀBreakthrough Technologies@ lever is expert judgment. It is assumed that, under an aggressive ᴀRapid Technology progress world,@ enhanced tight sands and coalbed methane technology, such as the injection of CO2, will lead to significantly improved recovery from unconventional gas reservoirs and wells.

11. Mitigating Environmental and Other Constraints on Development

Background and Problem

Development of unconventional gas, particularly in the Rocky Mountain basins, is constrained by concerns over air quality, land disturbance, water disposal and restricted Federal land and wilderness set-asides. These environmental and access constraints significantly slow the pace of drilling and, in some cases, exclude high potential areas from development.

Technology Lever

Federal lands legislatively or administratively excluded from access are set as ‗off limits‖ for development. Less severe development constraints may be mitigated or overcome by in-depth environmental assessments of the major constraints, the introduction of environmentally enhanced E&P technology such as low NO_x compressors, improved water treatment and environmentally neutral disposal methods, and the drilling of multiple, directional wells from a single well pad.

Impacts and Benefits

For those plays not included in basins recently studied under the Energy Policy and Conservation Act.

Attachment A

Case Studies of Technology Progress

1.   *Tight Gas Sands*. Piceance Basin, Colorado
        Williams Fork/Mesaverde Formation

2.   *Gas Shales*. Fort Worth Basin, North Texas
        Barnett Shale Formation

3.   *Coalbed Methane*. Uinta Basin, Utah
        Ferron Coal Trend

CASE STUDIES OF TECHNOLOGY PROGRESS

In support of our overall assessment of technology progress, we have assembled a series of "case studies." These case studies illustrate how technology, in aggregate, has changed the performance and costs of key unconventional gas plays.

The case studies of technology progress discussed in this report represent three major tight gas, gas shales and coalbed methane plays in the UGRSS data base.

$\quad$ $\$$ $\quad$ _Tight Gas Sands_. The recent development of the multi-Tcf size tight gas sands accumulation in southern Piceance Basin, Colorado, in the Williams Fork (Mesaverde) Formation.

$\quad$ $\$$ $\quad$ _Gas Shales_. The active development of an estimated (by Devon Energy, the field's operator) 10 to 20 Tcf of technically recoverable natural gas in the Barnett Shale of the Fort Worth Basin.

$\quad$ $\$$ $\quad$ _Coalbed Methane_. The development of coalbed methane in what has become Utah's largest natural gas and fastest growing natural gas play, the Ferron coals of the Uinta Basin.

$\qquad$ Each of these case studies illustrates a different aspect of technology progress in unconventional natural gas exploration and development. And, each provides guidelines for establishing the technology levers to be used in UGRSS.

CASE STUDY 1.
TIGHT GAS SANDS, PICEANCE BASIN, COLORADO
WILLIAMS FORK FORMATION/MESAVERDE

1. Background. The Piceance Basin contains a thick package of vertically stacked, lenticular sands in the Williams Fork/Mesaverde Formation. These tight gas sands contain an impressive volume of gas in-place, estimated at 300+ Tcf (Johnson and Others, 1987; ARI, 1997). Until recently, these sands were thought to be low productivity, high cost resources.

Regional geologic studies by the petroleum industry and the U.S. Geological Survey and detailed reservoir characterization at the MWX/Rulison Field site were instrumental in changing the outlook. These studies demonstrated that the basin-center Williams Fork Formation is widely gas charged and can be successfully developed in areas where thick, stacked sands and natural fractures coexist. Over the last decade, and particularly within the past five years, the integrated application of new E&P technologies has turned this uneconomic tight gas resource into an active, profitable gas play.   Today, these lenticular sands are the primary tight gas target in the Piceance Basin.

The improved economics, due mainly to higher reserves per well, are responsible for the Williams Fork/Mesaverde tight gas play in the southern Piceance Basin. During the 1980s, this gas play had only low productivity wells, mostly uphole completions or "bail-outs" of unproductive deeper targets. Today, over 1,200 wells have been drilled and produce nearly 300 MMcfd from these Williams Fork stacked lenticular tight gas sands. Four fields account for the great bulk of activity, Figure 3C-2:

- Rulison Field, with 293 active (310 total) wells and producing 88 MMcfd, leads the way.

- Grand Valley Field, with 327 active (334 total) wells and producing 87 MMcfd, has been the most active field in this gas play.

- Parachute Field, with 125 active (and total) wells and producing 48 MMcfd, establishes this gas play on the west.

- Mamm Creek Field, with 347 active (355 total) wells and producing 64 MMcfd, establishes this gas play on the east.

Most likely this tight gas sands development area will continue to grow, as the ultimate boundaries and remaining "sweet spots" of the Williams Fork tight sands are yet to be defined.

2. Natural Gas Development. The Juhan #1 Rulison discovery well, drilled in the late 1950s (Sec. 26, T6S R94W), had strong initial gas flows, giving expectations that the Williams Fork would become a new, economically attractive natural gas play. When subsequent wells proved to be much less productive, with reserves of 0.2 to 0.5 Bcf per well, the play was abandoned in search of deeper Mesaverde Group sands.

The redevelopment of the Williams Fork/Mesaverde began in the 1990s and has continued strong through today. Currently, 1,092 active wells produce 288 MMcfd, with 216 of these wells brought on production in 2002 and early 2003. To date, the Williams Fork has produced over 500 Bcf, from the Rulison, Grand Valley/Parachute, and Mamm Creek fields and is headed toward a multi-Tcf natural gas play. Table 3C-17 provides a summary of the development status and historical well performance for the four major Williams Fork Formation gas fields of the Piceance Basin, as of mid-2003.

Figure 3C-2. Major Williams Fork Formation Natural Gas Field Locations, Southern Piceance Basin.
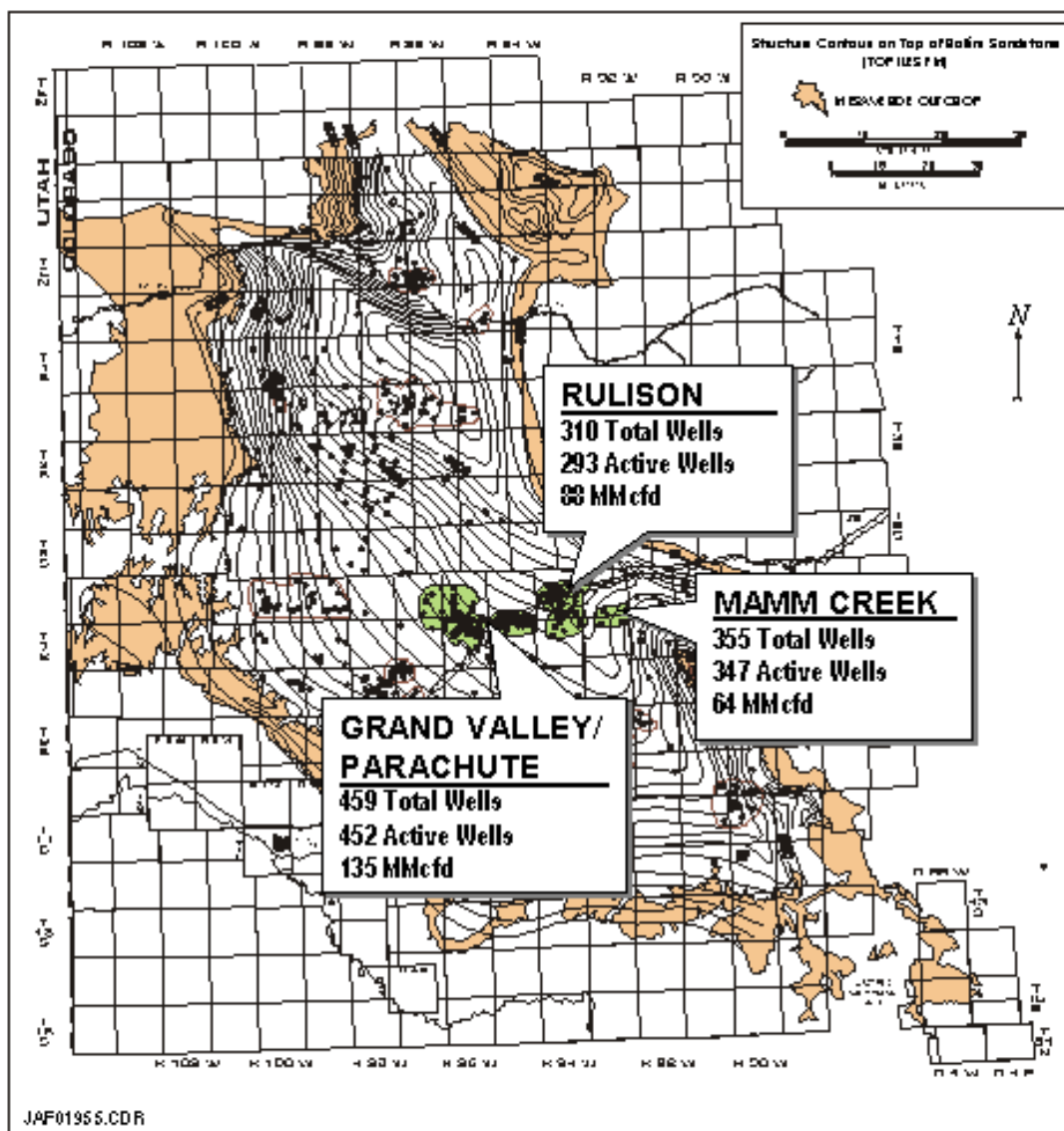
Source: Advanced Resources, International

Table 3C-17

Gas Development and Well Performance
Williams Fork Formation Gas Fields, Piceance Basin

Field	Total Wells	Active Wells	New Wells (2002-2003)	Gas Recovery		Well Performance	
				Cumulative (Bcf)	Estimated Ultimate (Bcf)	Cumulative/ Well (Bcf)	EUR/ Well (Bcf)
Rulison	310	293	56	186	450	0.62	1.48
Grand Valley	334	327	66	160	410	0.48	1.25
Parachute	125	125	58	54	300	0.43	1.55
Mamm Creek	355	347	36	111	190	0.32	0.86
Total	1,124	1,092	216	511	1,350		

3. Technology Progress Levers.

  a. Gas Recovery Per Well. The single most important technology progress measure for tight gas sands is improvement in gas recovery per well. Application of advanced well logging practices, lower damaging well completion methods, and higher efficiency hydraulic fracturing technology have led to progressive improvements in well performance for the Williams Fork tight gas sand fields in the southern portion of the Piceance Basin, measured in terms of estimated ultimate recovery (EUR) per well.

The well performance in these fields is shown in Table 3C-18 below for four key time periods, starting with the initial group of wells drilled before active development of these fields began in the mid-1990s.

Table 3C-18

Well Performance and Technology Progress
Williams Fork Formation Gas Fields, Piceance Basin.

Time Period	Number of Successful Wells	EUR/Successful Well (Bcf)	
		Mean	F50
Pre-1995	181	0.79	0.55
1995-1998	270	0.98	0.9
1999-2001	428	1.12	1.07
1/2002-6/2002	103	1.98	1.9
Recent	113	n/a	n/a
TOTAL	1,095		

Source: Advanced Resources, International

Figure 3C-3 provides the distribution in well performance for the same four time periods, including the active well drilling during the first half of year 2002. As additional production data are obtained on the more recently drilled 113 wells, these wells will be added to the year 2002 performance time period.

The analysis of changes in well performance, due to improved knowledge and technology, shows that the mean EUR per well has improved steadily from 0.79 Bcf for the pre-1995 wells to 1.98 Bcf for the year 2002 wells. (The F50 (median) well performance value shows even greater, three-fold improvement in well performance between the initial group of pre-1995 wells and the year 2002 wells.)

   b. Dry Holes. While dry holes, particularly "economic dry holes" (wells with ultimate gas recovery of less than 0.1 Bcf) are not a major consideration in this tight gas play, the data show a steady improvement in this technology progress factor, as shown in Table 3C-19.

Figure 3C-3. Well Performance and Technology Progress, Williams Fork Fomation Gas Fields, Piceance Basin.
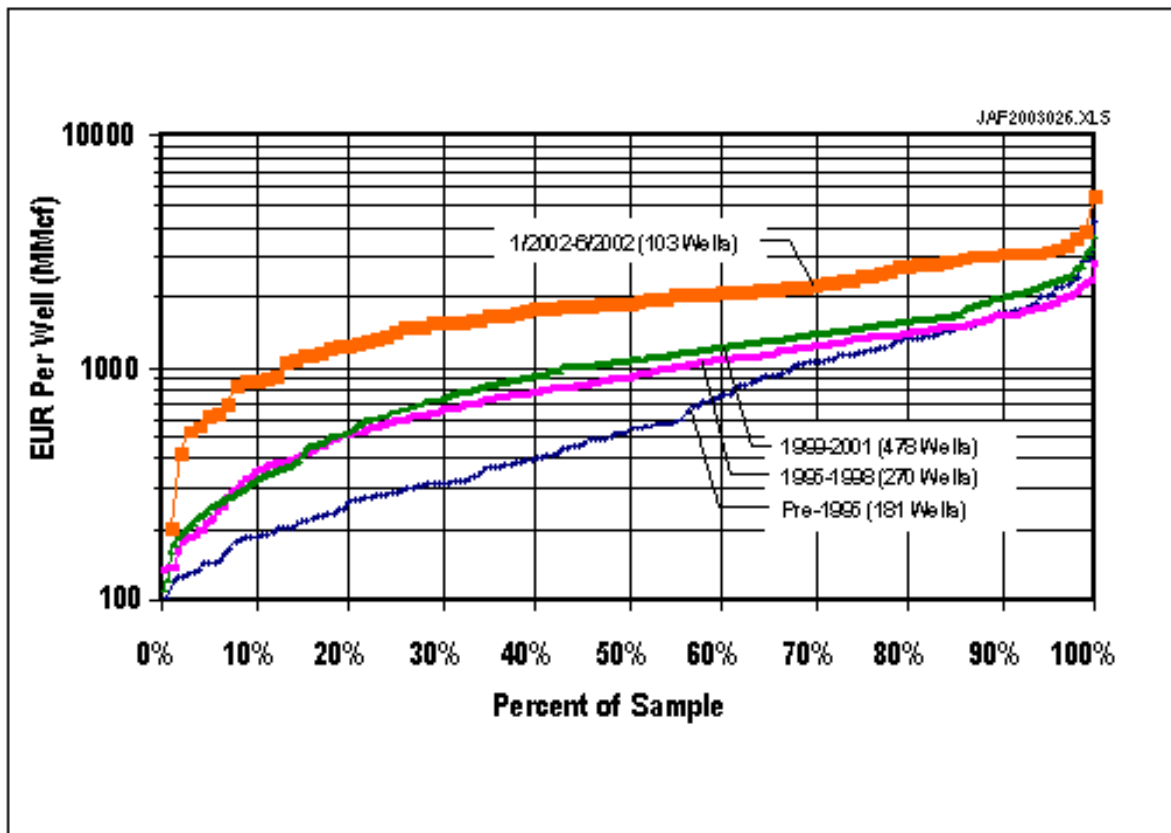
Source: Advanced Resources, International

Table 3C-19

Dry Hole Rate and Technology Progress
Williams Fork Formation Gas Fields, Piceance Basin

Time Period	Total Wells	Successful Wells	Dry Wells	% Successful
Pre-1995	199	181	17	91%
1995-1998	279	270	9	97%
1999-2001	430	428	2	99%
1/2002-6/2002	103	103	-	100%
Recent	113	113	-	N/a
TOTAL	1,124	1,095	28	

Source: Advanced Resources, International

The analysis of the change in dry hole rates, due to improved knowledge and technology, shows that the dry hole rate has steadily declined from 9% for the pre-1995 wells to essentially zero for wells drilled since 1998.

c. Recompletion-Based Reserve Growth. An aggressive program of well recompletions and completion of behind-pipe formations has enabled these four fields to add 84 Bcf of reserve growth-based reserves, as shown in Table 3C-20.

Table 3C-20

Reserve Growth and Technology Progress
Williams Fork Formation Gas Fields, Piceance Basin

Time Period	Total Wells	Successful Wells
Pre-1995	93	72
1995-1998	20	12
1999-2001	-	-

Source: Advanced Resources, International

The recompletion program has added approximately 10% to the original proved reserves in these four tight gas fields but, more importantly, has significantly improved the performance of wells that were considered marginal or uneconomic based on their original completion.

d. Natural Fracture Prediction. A major natural fracture prediction R&D project was conducted in the Williams Fork tight sands of the Rulison Field. The project, using a combination of 3-D seismic, coherency mapping and a geomechanical stress model, identified a natural fracture cluster area (a permeability "sweet spot") that covers three sections in the southern portion of the Rulison Field (Figure 3C-4).

Wells drilled in this "sweet spot" area of the southern Rulison Field have reserves two or more times higher than reserves for wells drilled outside this area, giving confidence that "tight gas sand selectivity technology" could be developed and applied to future tight sand exploration and production.

e. Field Development and Well Spacing. An active program of intensive infill development is underway in the Williams Fork tight gas sands of the Rulison Field. In Section 20 (T6S, R94W) of this field, the operator has initiated a 20 acre per well (32 wells per section) field development and well spacing pilot (Figure 3C-5). Subsequently, the field operator has applied for and has begun an even more intensive development, adding additional wells, further reducing the spacing to 16 acres per well, on the way to a 10 acre per well test. The results of this pilot have been encouraging and indicate steadily increasing natural gas recoveries from this infill program, Table 3C-21 below:

Table 3C-21

Intensive Field Development and Technology Progress
Williams Fork Formation. (Sec. 20, T6S, 94W, Rulison)

Date	Wells and Spacing	Reserves/Well* (Bcf)	Total Reserves (Bcf)
Initial	First 2 wells @320A/W**	2.1	4
1994	Next 2 wells @160 A/W	2.2	4
1995	Next 4 wells @80 A/W	1.9	8
1996-1997	Next 6 wells @40 A/W	1.7	10
1997-2000	Next 16 @20A/W	1.7	28
2001-2002	Next 10 wells (@ 16 A/W)	2	20
TOTAL (40 wells)		1.85	74

*Estimated Based on History Matching With ARI-Tight Type Curve Model.
**After subsequent well recompletions.

Source: Advanced Resources, International

4. Summary. The cumulative effects of the technology progress actions discussed in this case study, have greatly improved the economic potential of the Williams Fork Formation tight gas field at Rulison and similar tight gas fields in the southern Piceance Basin. In addition, as is being demonstrated in the Rulison Field, the combined application of improved technology and intensive resource development has the potential to convert a modest and marginal gas 90 Bcf prospect into a major multi-Tcf natural gas field, as shown in Table 3C-22.

Figure 3C-4. Geomechanics and 3-D Seismic Based Technology Progress, Williams Fork Formation
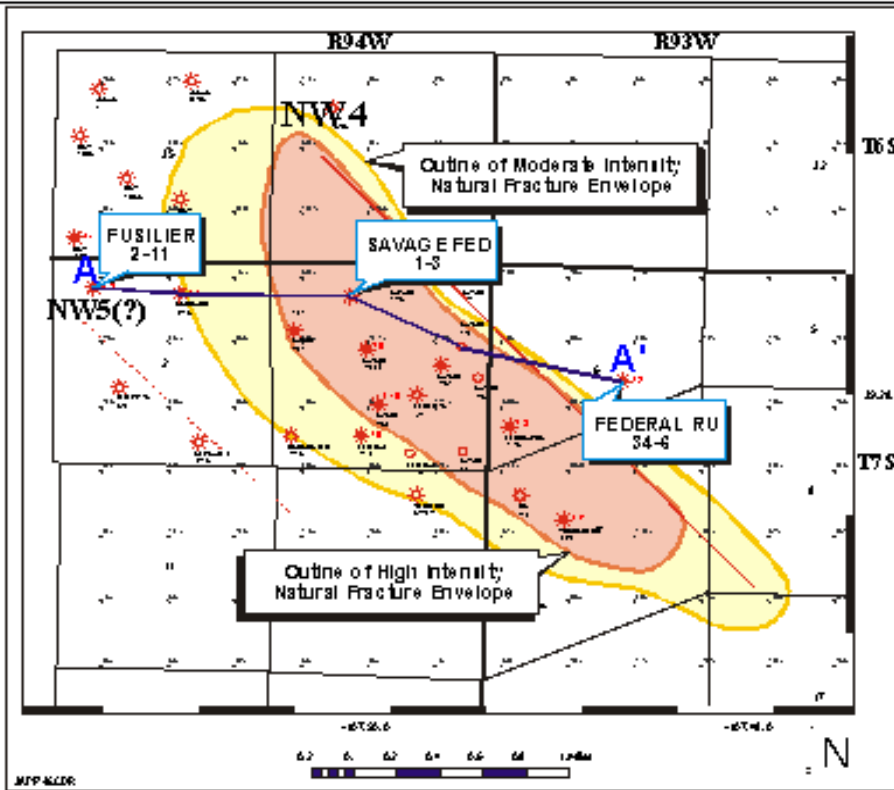
Results of Geomechanics/3-D Seismic Technology Test

Natural Fracture Cluster Area	Cum. Recovery (Bcf)	Est. Ult. Recovery (Bcf)
Inside Envelope (12 wells)		2.5 Bcf/Well
• Savage Fed 1-3	2.0	2.8
Outside Envelope (23 wells)		1.2 Bcf/Well
• Fed. RU 34-6	0.2	0.3
• Fusiler 2-11	0.8	1.5

Source: Advanced Resources, International

Figure 3C-5. Location of Intensive Field Development Pilot, Section 20 Rulison Field.
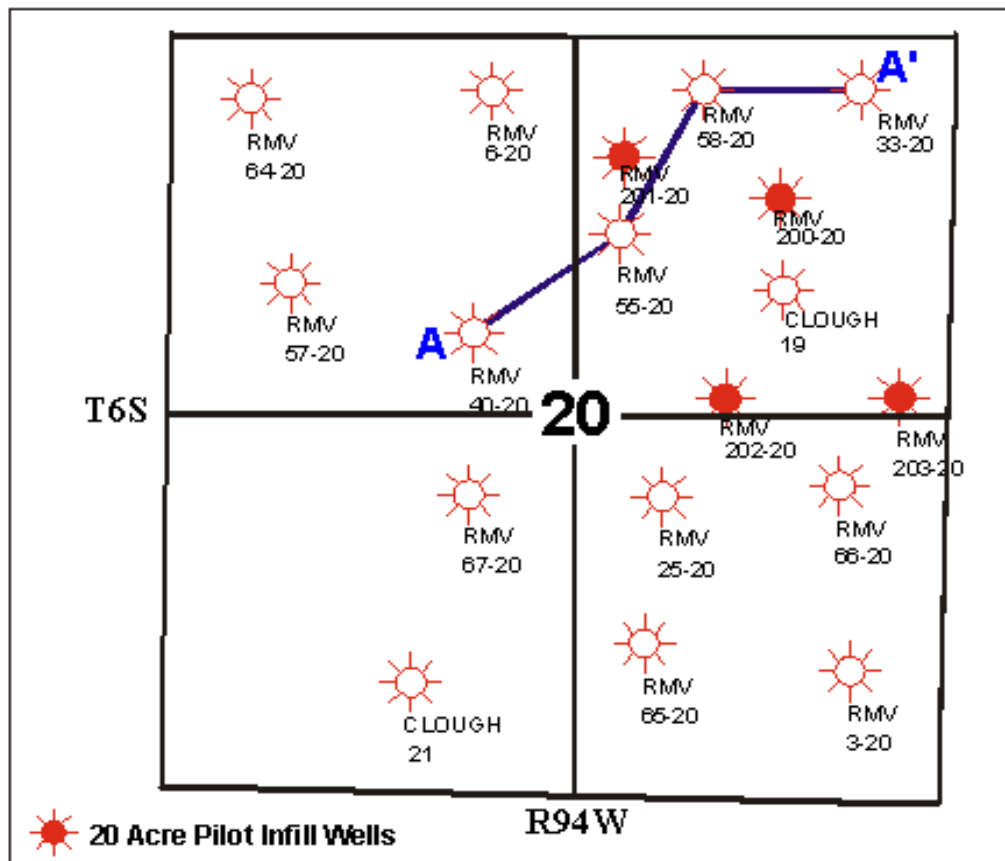
Source: Advanced Resources, International

Table 3C-22

**Impact of Technology Progress and Intensive
Resource Development, Rulison Field, Piceance Basin.**

Field Development Options	Well Spacing (A/W)	No. of Locations*	Success Rate (%)	Reserves/ Well (Bcf)	Reserves/ Section (Bcf)	Potential Field Size (Bcf)
Historical Practices	160	120	91	0.79	3	90
Advanced Strategy	16	1,200	99	1.85	74	2,200

*Assuming 30 square mile productive field area.

Source: Advanced Resources, International

CASE STUDY 2.
GAS SHALES, FORT WORTH BASIN, NORTH TEXAS
BARNETT SHALE FORMATION

1. Background. The Fort Worth Basin holds the Mississippian-age Barnett Shale, an organically rich, low-permeability unconventional gas accumulation (Figure 3C-6). These gas shales are estimated to hold 120 Tcf of gas in-place, based on recent estimates prepared by Devon Energy (Petroleum News, May 2003).

In the early 1990s, the Gas Research Institute supported a series of reservoir characterization and engineering studies that contributed significantly to improved understanding the gas storage mechanisms and gas production for this new gas play. Resource assessments by the USGS (USGS, 1995) and a subsequent USGS open-file study (Schmoker, 1996) provided the initial information on the resource potential of the Barnett Shale gas accumulation, estimating its technically recoverable resource potential at a modest 1 to 3 Tcf. A subsequent combined Advanced Resources and USGS joint study, published in the Oil and Gas Journal (Kuuskraa, 1998), updated the well performance and understanding of the actual drainage being achieved by wells in this gas play. The study set forth that the Barnett Shale might hold 10 Tcf of technically recoverable natural gas, greatly raising the visibility of this potential gas resource.

Today, Devon Energy, the Barnett shale's dominant producer with 10 times more production than any other operator, estimates that:

*   Potentially 10 Tcf, or 8% of the estimated 120 Tcf of gas in-place, can be recovered using current technologies; and,
*   Another 10 to 12 Tcf, or 8% to 10% of the gas in-place, may be recoverable with advanced technology, particularly with the use of horizontal, fraced wells.

2. Natural Gas Development. The development of the Barnett Shale began in the mid-1980s in the Newark East Field currently the primary natural gas field in the Barnett Shale gas play. Development progressed slowly as the early wells had low reserves, with an occasional high productivity well.

With steadily improving results based on using "light sand fracs" and completing a larger shale interval, starting in the mid-1990s, drilling in the Barnett shale accelerated. Today, nearly 1,800 wells have been drilled into the Barnett Shale, with gas production reaching 550 MMcfd. To date, the Barnett shale has produced a cumulative of over 600 Bcf. Table 3C-23 below provides a summary of Barnett Shale natural gas production and development through the end of 2002.

Figure 3C-6. Barnett Shale Development Area, Fort Worth Basin, North Texas.

Productive Area. Area of existing production: 500 mi²

Prospective Area. Along strike of existing production and updip to -2,000 m Ellenburger structural contour (high thermal maturity): 2,500 mi²

Maximum Area. Updip to -1,600 m Ellenburger structural contour (lower thermal maturity): 4,200 mi²
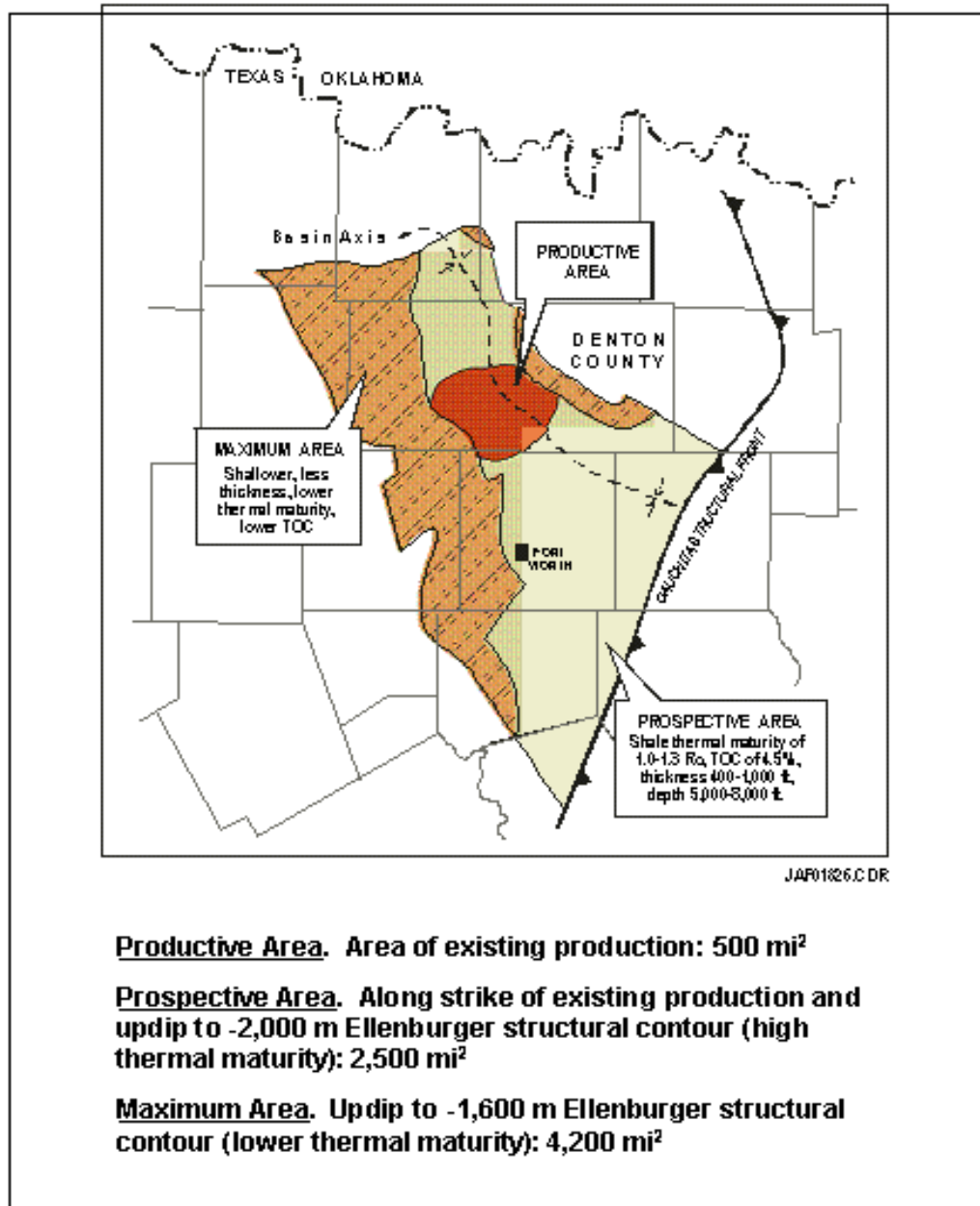
Source: Advanced Resources, International

Table 3C-23

Growth in Barnett Shale Production and Wells

Time Period	Annual Production (Bcf)	Cumulative Production (Bcf)	End of Year Producing Wells
1990	3	12	66
1995	20	70	242
1999	40	198	517
2000	78	276	698
2001	131	407	1,171
2002	202	609	1,771

Source: Advanced Resources, International

3. Technology Progress Levers

a. Gas Recovery Per Well. Gas recovery per well has steadily improved as operators have changed their well completion practices by completing a larger portion of the shale interval (adding the Upper Barnett zone to the Lower Barnett zone), by introducing more effective (and lower cost) "light sand frac" technology, and by refracing previously completed wells.

The combined application of these technologies have enabled well performance, the key technology progress parameter, to steadily improve with time, as set forth in Table 3C-24 below.

Table 3C-24

Well Performance and Technology Progress
Barnett Shale, Fort Worth Basin.

Time Period	Average EUR/Well (Bcf)
• Initial Wells (74 wells, 1985-1989)	0.35
• Subsequent Wells (180 wells, 1985-1995)	0.86
• All Wells (1,909 wells, 1985-2002)	1.23
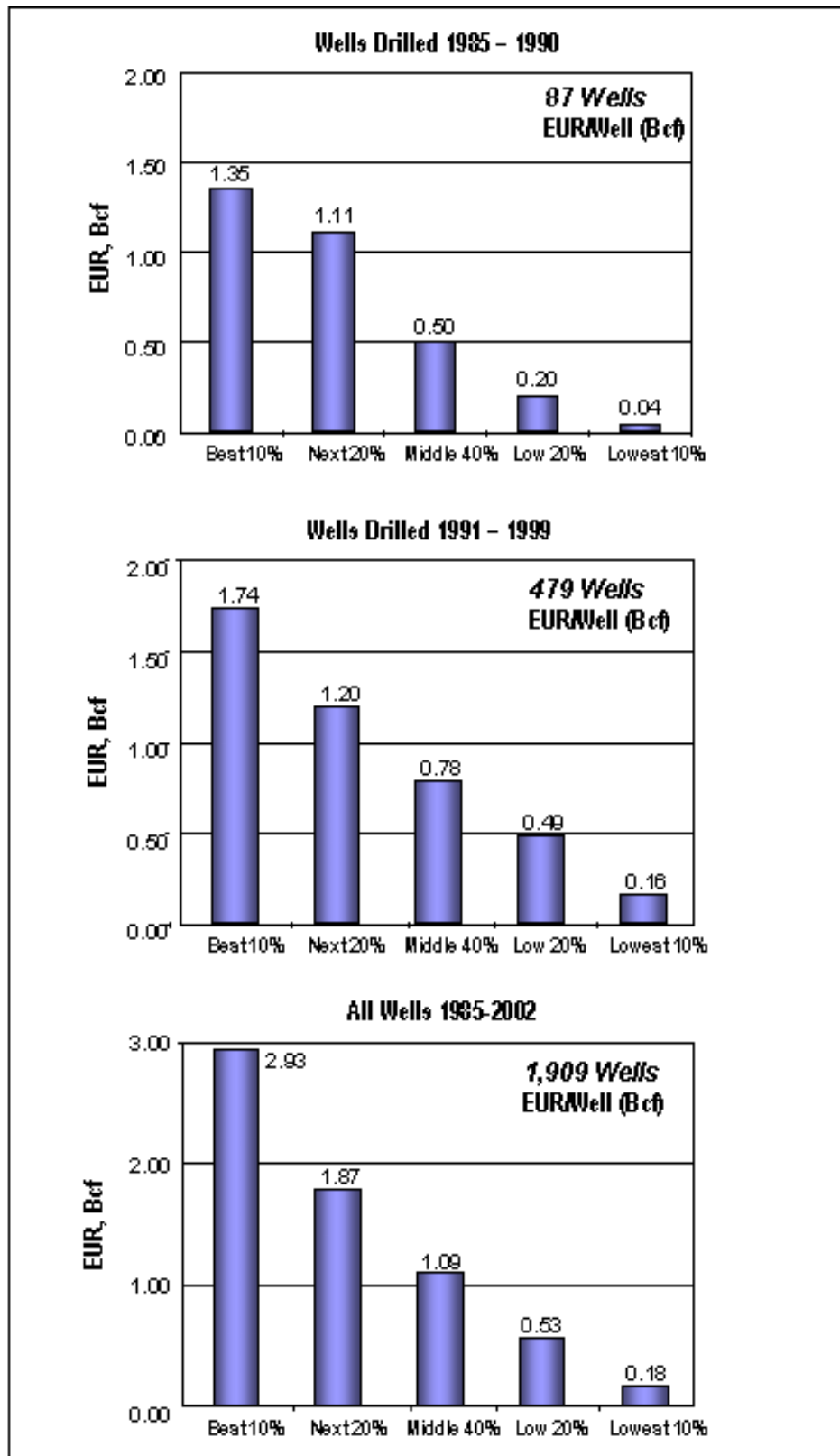
Source: Advanced Resources, International

Figure 3C-7. Gas Recovery Per Well and Technology Progress, Barnett Shale, Fort Worth Basin.

Using a separate data set of wells, Figure 3C-7 shows that the well performance for the middle 40% of the wells has increased from 0.5 Bcf for the 87 producing wells drilled through 1990 to 1.1 Bcf for all 1,909 producing drilled through 2002.

b. Success Rate. The success rate, another important technology progress parameter, has improved from 86% (150/180) for the initial 180 wells drilled through 1996 to 96% (1,909/1985) for all Barnett shale wells drilled to date.

c. Recompletion Based Reserve Growth. Considerable recompletion and refracturing has taken and is taking place in the Barnett Shale, particularly for the older wells. Table 3C-25, that provides the original and the latest distribution of well performance for the 87 wells drilled between 1985 and 1990, shows that application of this technology has improved performance for the middle 40% of these wells from 0.50 Bcf/well, as originally completed, to 1.44 Bcf/well after recompletion and refracturing.

Table 3C-25

**Well Recompletion Based Reserve Growth and Technology
Progress, Barnett Shale, Fort Worth Basin**.

Distribution	As Originally Completed (First 87 Wells Drilled 1985-1990) EUR/Well	After Recompletion (First 87 Wells Drilled 1985-1990) EUR/Well
Top 10%	1.35	3.50
20%	1.11	2.41
Middle 40%	0.50	1.44
20%	0.20	0.54
Bottom 10%	0.04	0.04

Source: Advanced Resources, International

d. General Resource Growth. The estimated ultimate size of the Barnett Shale gas resource has steadily increased, as the understanding of this gas play has grown, as well performance has improved, and as the field has been more intensely developed, on smaller well spacings. Table 3C-26 shows the steady progress in the estimated technically recoverable resource for the Barnett Shale, from 1.4 Tcf in 1990, to 3.4 Tcf in 1996, and to 10 Tcf in 1998.

Recently, based on still additional improvements in well performance (as discussed

above), even more intensive development (well spacing of 27 acres per well), and expansion in the defined areal extent of the productive area, this gas play's primary operator, Devon Energy, places the technically recoverable potential of the Barnett Shale at 20 Tcf.

Table 3C-26

**Increase in Resource Size/Productivity and Technology
Progress, Barnett Shale, Fort Worth Basin**

Time Period	Initial* Assessment, 1990	USGS Special* Assessment, 1996	Latest Assessment, 1998**
Development Intensity (Acres/Well)	320	320	80 to 320
Completed Wells			
Productive	74	180	300
Unproductive	12	30	50
Play Area, Square Miles	2,439	2,439	2,439
Future Wells	4,792	4,668	10,148
Success Rate	0.86	0.86	0.86
EUR/Well (Bcf)	0.35	0.84	0.35 to 1.50
Technically Recoverable Resources (Tcf)	1.4	3.4	10

*Source: USGS (1990, 1996)
**Source: Advanced Resources, International/USGS, 1998

  e. Lower Well Costs. Improved drilling and completion practices and substitution of new "light sand frac" technology for previous high cost gelled fluids and large volume sand treatments, steadily reduced overall well drilling and completion costs even as a large shale interval is being completed. Increasing rig day rates drove well drilling and completion costs back up in 2001 to nearly $900,000 per well. Since then improvements in rig efficiency and lower infrastructure costs for infill wells are, once again, enabling drilling and completion costs to decline to a projected $750,000 per well, Figure 3C-8.

  f. Horizontal Wells. Horizontal well technology is starting to be applied in the Barnett Shale. While it is still too early to conclusively establish its performance, early indications based on gas flow rates are encouraging. The horizontal wells drilled to date have initial flow rates two to four times of a vertical well with well drilling and completion costs about two times a vertical well.
  Devon has announced that it would drill 50 horizontal wells into the Barnett Shale in 2003, with seven horizontal wells already on line, producing an aggregate 15 MMcfd. Approximately half of the new horizontal wells would be drilled in Devon's core area at Newark East field, in Wise and Denton Counties of North Texas, the dominant Barnett Shale gas field. The remainder of the horizontal wells would be used to establish the viability of the relatively unexplored areas outside the core areas.

4. SUMMARY. The overall progress in Barnett Shale development technology, including improved well performance, lower costs and intense resource development, is summarized in Table 3C-27.

-   Finding and development (F&D) costs, the overall well critical technology progress measure, has declined for the Barnett Shale by three fold, from a range of $1.50 to $2.00

per Mcf for the initial wells (drilled in the late 1980s) to about $0.75 per Mcf for wells drilled in 2001 and 2002. Further reductions in F&D costs are projected, by the field's operator, for 2003.

- Reserves per well have steadily increased from about 0.5 Bcf per well for the initial wells to 1.2 Bcf per well for recent wells. Assuming continued improvements in completion technology the average recovery per well could reach 2 Bcf over the full impact of the refrac program is realized in both previously drilled and newly drilled wells.

- Improvements in rig efficiencies and use of lower cost, more effective fracturing technology are helping counter increased rig day rates, helping to hold down overall well D&C costs.

Figure 3C-8. Drilling Costs and Technology Progress, Barnett Shale, Fort Worth Basin.

- Improved rig efficiency (2 wells/rig/month)
- Core area wells have lower costs due to existing infrastructure
- Results in 15% savings or $135,000/well
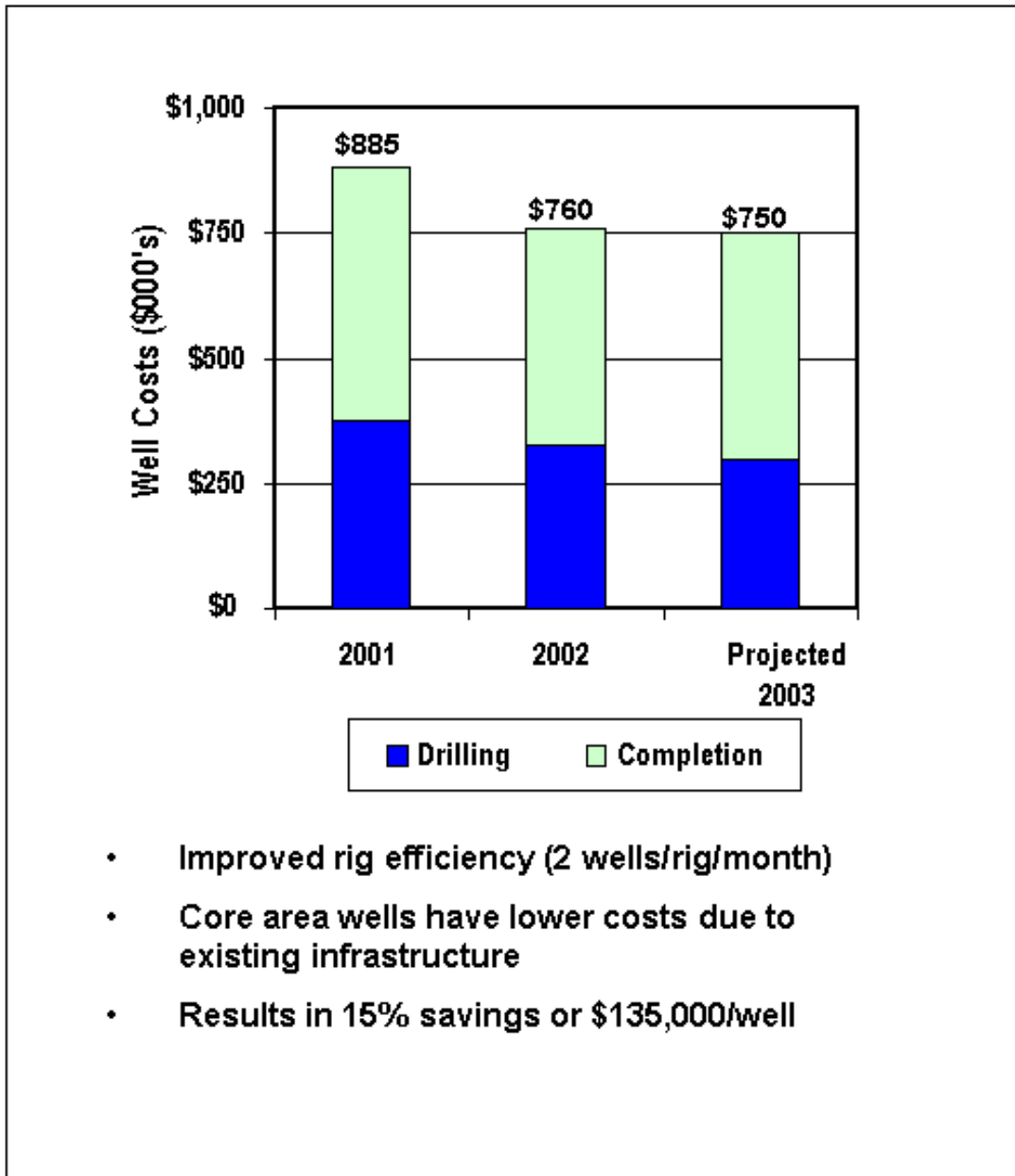
Source: Advanced Resources, International

Table 3C-27

**Impact of Technology Progress and Improved Well
Drilling and Completions, Newark East Field, Fort Worth Basin.**

Time Period	Pre-1991	1991-95	1996-2000	2001-02	2003
No. Producing Wells	66	176	456	1,073	n/a
Well Spacing	320 acres	160-320 acres	55-110 acres	27-55 acres	27 acres
Completion Interval	L. Barnett	L. Barnett	U./L. Barnett	U./L. Barnett	U/L Barnett
Progress in Drilling and Completion Technology	Variety of Completion Practices	MHF Technology	Introduction of Waterfrac Technology	Widespread Use of Waterfracs	Improved Rig Efficiencies
Typical Well Cost	$600-$1,000K	$600-$850K	$500-$750K	$750-$900K	$700-$800K(e)
Typical Well EUR	0.4-0.5 Bcf	0.8 Bcf	1.0 Bcf	1.0-1.2 Bcf	1.25 Bcf
F&D Costs	$1.50-$2.00	$0.75-$1.10	$0.50-$0.75	$0.75	$0.60(e)

Source: Advanced Resources, International

CASE STUDY 3.
COALBED METHANE, UINTA BASIN, UTAH
FERRON COAL TREND

1. Background. The Uinta Basin contains a thick section of Upper Cretaceous coals within the Ferron Sandstone Member of the Mancos Shale (Figure 3C-9). These coals have been estimated to contain on the order of 10 Tcf of gas in-place (Advanced Resources, 1996). Prior to 1990, these coals were bypassed in search of deeper conventional sandstone reservoirs.

Early resource characterization studies (sponsored by the Gas Research Institute) began to provide some of the basic reservoir data for this new gas play, such as gas content, coal depth and coal thickness. These studies and core data showed that the gas content of the coals decreased dramatically from north to south, independent of the rank and maturity of the coals. Regional mapping also indicated that the productive areas are associated with the updip stratigraphic pinchouts where the tight marine shales provide a seal enabling the coals to become "supercharged" with biogenic and migrated thermogenic gas from the southern basin margin.

Improved understanding of this gas play, including advanced well completion technology has led to steadily increasing reserves per well from the coalbed methane play in this basin. Today, over 600 well have been drilled and produce 250 MMcfd from the Ferron coalbed methane trend. The Drunkards Wash Field, in the northern portion of the Ferron Coal Trend accounts for the great bulk of the wells and gas production (Figure 3C-10).

2. Natural Gas Development. The Ferron coalbed methane play was discovered in 1988 by Texaco E&P, Inc. at the northern end of the Ferron Trend, near Price. After several years of inactivity, Texaco and others began active exploration in the mid-1990s.

To date the Ferron CBM play has produced a cumulative of 400 Bcf, and has proved reserves of 1,700 Bcf, making this a multi-Tcf giant natural gas play, primarily from Drunkards Wash, Helper and Buzzards Bench fields.

a. Ability to Identify Higher Productivity Well Performance Areas. Table 3C-28 provides a summary of the well drilling and well performance for the Drunkards Wash CBM field as of the end of 2002.

Figure 3C-9. Drunkard's Wash Ferron Coalbed Methane Field, East-Central Utah
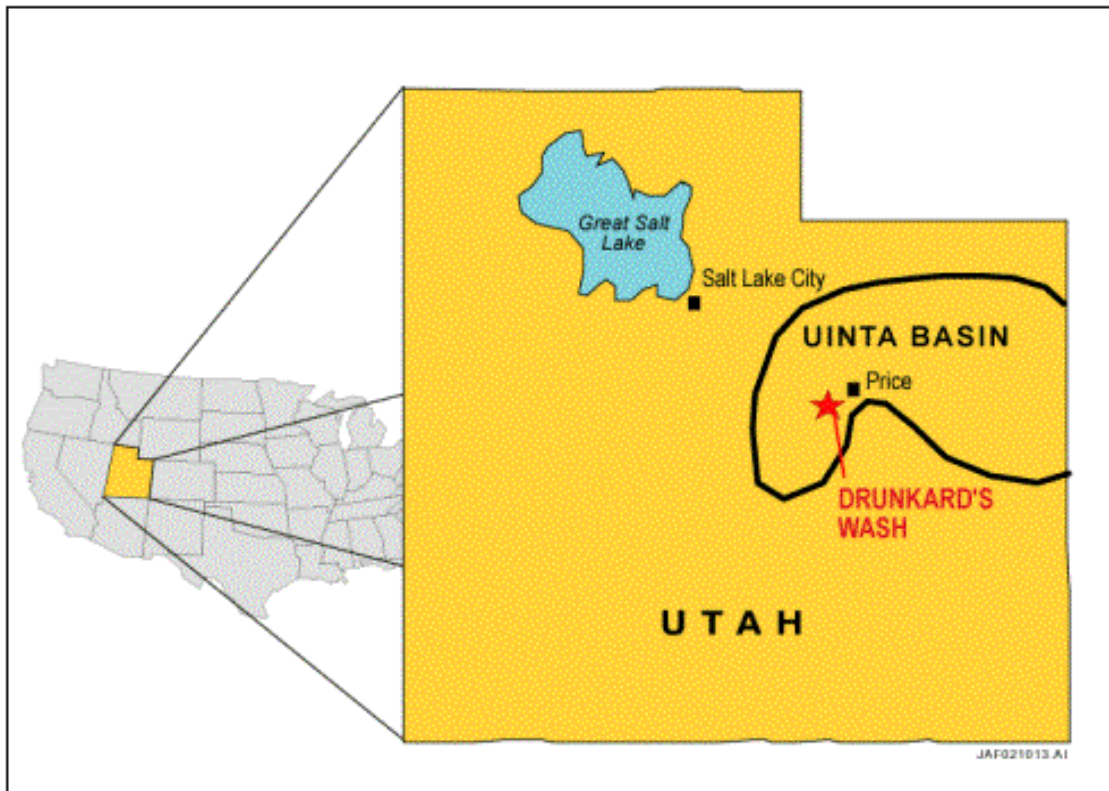
Source: Advanced Resources, International

Table 3C-28

**Well Performance Selectivity and Technology Progress
Drunkard's Wash CBM Field, Uinta Basin**.

Time Period	Number of Successful Wells	EUR/Successful Well (Bcf) Mean
Pre-1995	78	3.4
1995-1998	103	2.7
1999-2000	149	2.0
2001	78	1.7
TOTAL	407	

Source: Advanced Resources, International

Looking at the history of well performance, where the more recent wells have lower EUR's than the marginal wells.

Table 3C-29 provides a perspective on this question and shows that the initial wells have, in general, been able to target the better 60% of the field placing 72% (293 of the 407) wells drilled to date in this portion of the field.

The analysis of well performance shows that the companies have been able to target the initial wells on the higher productivity, 3.4 Bcf/well area and now are steadily moving development toward the lower productivity, lower coal thickness portions of this gas play.

b. Dry Holes. While dry holes, particularly "economic dry holes" (wells with ultimate gas recovery of less than 0.1 Bcf) are not a major consideration in this CBM play, the data show little change in this technology performance factor (Table 3C-30). The dry hole rate has remained at 97% to 100% essentially the same over time, for wells drilled in this play.

Table 3C-29

Selectivity and Technology Progress, Drunkards Wash
Coalbed Methane Field, Uinta Basin.

Well Distribution	Expected Well Selection Distribution			Actual Well Selection Distribution				
	Avg. Well (Bcf)	Range (Bcf)	No. Wells	Pre-1995	1995-1998	1999-2000	2001	TOTAL
Top 10%	6	>5	200	14	12	8	2	36
Next 20%	4	3-5	400	26	25	24	15	90
Middle 30%	2	1-3	600	28	43	71	25	167
Lowest 40%	0.5	0.1-1	800	10	22	46	36	114
No. of Wells			2,000	78	103	149	78	407
Average Well (Bcf)	2.0			3.4	2.7	2.0	1.7	2.4

Source: Advanced Resources, International

Table 3C-30

Dry Hole Rate and Technology Progress
Ferron Coal Trend, Uinta Basin

Time Period	Total Wells	Successful Wells	Dry Holes	% Successful
Pre-1995	84	84	0	100%
1995-1998	136	132	4	97%
1999-2000	194	189	5	97%
2001	107	107	-	100%
Recent	18	18	-	N/a
TOTAL	539	530	9	

Source: Advanced Resources, International

4. Summary. The case study of the coalbed methane development in the Ferron Coal Trend helped establish the well productivities, dry hole rates and resource size for this important new natural gas play. It also demonstrates that for coalbed methane plays, where coal thickness and gas content are readily measured and can be regionally mapped, producers will have the ability to "high grade" their early development to pursue areas with higher potential for CBM development. This provides guidance on how to allocate and forecast the initial field development practices and expectations for well performance in coalbed methane.

Appendix 3-D. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

X **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service=s 2000 hydrocarbon resource assessment.[1] New discoveries between 1999 and 2003 were subtracted form the undiscovered resources allocated to the corresponding evaluation unit.

X **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.

X **Producing Fields.** The fields in this category have wells that have produced oil and/or gas by 2005. The production volumes are from the Minerals Management Service database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters. The crosswalk between region and evaluation unit is shown in Table 3D-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is determined in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on MMS=s latest[1] resource assessment (Table 3D-2). The volume of resource in barrels of oil equivalence by field size class as defined by the MMS is shown in Table 3D-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. The total number of undiscovered fields as of August 31, 2006 in the OOGSS is 3,379. Fields smaller than field size class 2 are assumed to be uneconomic to develop. Resources in the Pacific, Atlantic, and Eastern GOM (except lease sale 181) are currently under drilling moratoria and are not available for exploration and development.

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[1]U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S.OCS Oil and Natural Gas Resources*, February 2006.

Table 3D-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Table 3D-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, Oil and Gas Division

Table 3D-3. MMS Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Minerals Management Service

Determination of Discoveries

The number and size of discoveries is determined based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

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

where,

TotalFields	=	Total number of fields by evaluation unit and field size class
CumNFW	=	Cumulative new field wildcats drilled in an evaluation unit
γ	=	search coefficient
EU	=	evaluation unit
iFSC	=	field size class.

The search coefficient (γ) was chosen to make the Equation 3D-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates for a search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to provide enough data points to determine a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. A polynomial was fit to the resulting search coefficients as follows:

$$\gamma_{\text{EU,iFSC}} = \beta1 * \text{iFSC}^2 + \beta2 * \text{iFSC} + \beta3 * \gamma_{\text{EU,10}} \tag{3D-2}$$

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[2]Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

where,

$$\beta1 = 0.0882\ 0.198 \text{ for Western GOM and } 0.198 \text{ for Central and Eastern GOM}$$
$$\beta2 = -1.15173 \text{ for Western GOM and } -3.468 \text{ for Central and Eastern GOM}$$
$$\beta3 = 7.4277 \text{ for Western GOM and } 15.812 \text{ for Central and Eastern GOM}$$
$$iFSC = \text{field size class}$$
$$\gamma = \text{search coefficient for field size class 10.}$$

Cumulative new field wildcat drilling is determined by

$$CumNFW_{EU,t} = CumNFW_{EU,t-1} + \alpha1_{EU} + \beta_{EU} * (OILPRICE_{t-nlag1} * GASPRICE_{t-nlag2}) \tag{3D-3}$$

where,

$$OILPRICE = \text{oil wellhead price}$$
$$GASPRICE = \text{natural gas wellhead price}$$
$$\alpha, \beta = \text{estimated parameter}$$
$$nlag1 = \text{number of years lagged for oil price}$$
$$nlag2 = \text{number of years lagged for gas price}$$
$$EU = \text{evaluation unit}$$

The decision for exploration and development of the discoveries determine from Equation 3D-1 is performed at a prospect level that could have more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3D-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3D-2.

Figure 3D-1. Prospect Exploration, Development, and Production Schedule
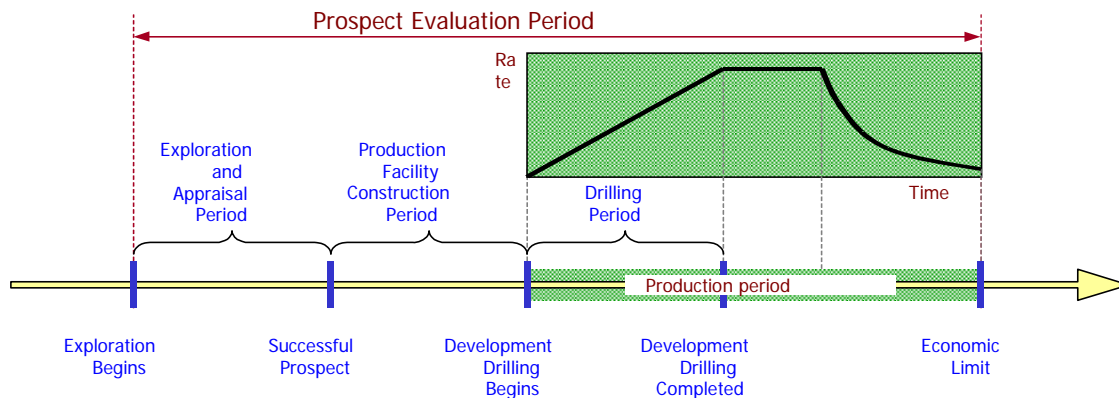
Source: ICF Consulting

Figure 3D-2. Flowchart for the Undiscovered Field Component of the OOGSS
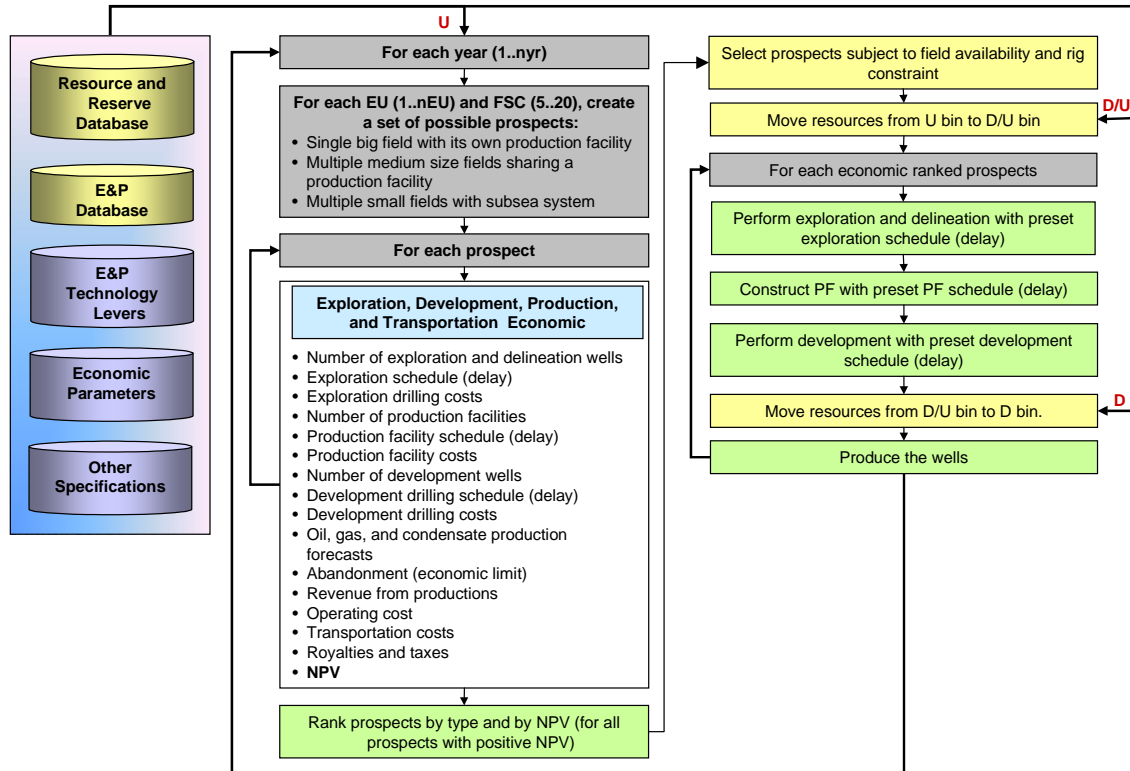
Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed.

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$ExplorationDrillingCosts(\$ / well) = 2,000,000 + 5.0E - 09 * WD * DD^3 \qquad (3D-4)$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in

water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts}(\$ / \text{well}) = 2,500,000 + 200 * (\text{WD} + \text{DD})$$
$$+ \text{WD} * (400 + 2.0\text{E-}05 * \text{DD}^2)$$

(3D-5)

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts}(\$ / \text{well}) = 7,000,000 + 1.0\text{E} - 05 * \text{WD} * \text{DD}^2$$

(3D-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 are limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\text{StructureCost}(\$) = 2,000,000 + 9,000 * \text{SLT} + 1,500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2$$

(3D-7)

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform which is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the tower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells, however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1,500,000 + 2,000 * (\text{WD} - 1,000))$$

(3D-8)

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the

dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\text{StructureCost(\$)} = (SLT + 30) * (3,000,000 + 750 * (WD - 1,000)) \tag{3D-9}$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost(\$)} = (SLT + 20) * (7,500,000 + 250 * (WD - 1,000)) \tag{3D-10}$$

Spar Platform (SPAR). Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost(\$)} = (SLT + 20) * (3,000,000 + 500 * (WD - 1,000)) \tag{3D-11}$$

Subsea Wells System (SS). Subsea systems range from single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well are 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.

$$\text{SubseaTemplateCost(\$/ well)} = 2,500,000 \tag{3D-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3D-4.

Table 3D-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$DevelopmentDrillingCost(\$/well) = 1,500,000 + (1,500 + 0.04*DD)*WD$$
$$+(0.035*DD - 300)*DD$$

(3D-13)

For water depths greater tan 900 meters,

$$DevelopmentDrillingCost(\$/well) = 4,500,000 + (150 + 0.004*DD)*WD$$
$$+(0.035*DD - 250)*DD$$

(3D-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 3D-5.

Table 3D-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001 - 20,000	> 20,000
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- X primary oil and gas production costs,
- X labor,
- X communications and safety equipment,
- X supplies and catering services,
- X routine process and structural maintenance,
- X well service and workovers,
- X insurance on facilities, and
- X transportation of personnel and supplies.

Annual operating costs are determined by

$$OperatingCost(\$/structure/year) = 1,265,000 + 135,000*SLT + 0.0588*SLT*WD^2$$

(3D-15)

Transportation

It is assumed in the model that existing trunk pipelines will be used, and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend upon the type of production technology used. The abandonment costs for fixed platforms and compliant towers assume the structure is abandoned. The costs for tension leg platforms, converted semi-submersibles, and converted tankers assume that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based upon historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical project development in the offshore consists of the following phases:[3]

- X   Exploration phase,
    - S   Exploration drilling program
    - S   Delineation drilling program
- X   Development phase,
    - S   Fabrication and installation of the development/production platform
    - S   Development drilling program
    - S   Pre-drilling during construction of platform
    - S   Drilling from platform
    - S   Construction of gathering system
- X   Production operations, and
- X   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 which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

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[3]The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one finds the field and three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends upon the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3D-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Table 3D-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	Water Depth (Feet)														
Number of Slots	0	100	400	800	1000	1500	2000	3000	4000	5000	6000	7000	8000	9000	10000
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS								3	3	3	4	4	4	4	5

Source: ICF Consulting

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$DevelopmentWells = 5 / FSC * FSIZE^{\beta_{DepthClass}}$$ (3D-16)

where,

FSC = field size class
FSIZE = resource volume
β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

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 3D-7.

Table 3D-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
6000	24		1000	4		4
7000	24		2000	4		4
8000	20		3000	4	4	4
9000	20		4000	4	4	4
10000	20		5000	3	3	3
11000	20		6000	2	2	2
12000	16		7000	2	2	2
13000	16		8000	1	1	1
14000	12		9000	1	1	1
15000	8		10000	1	1	1
16000	4					
17000	2					
18000	2					
19000	2					
20000	2					
30000	2					

Source: ICF Consulting

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3D-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.

Figure 3D-3. Undiscovered Field Production Profile
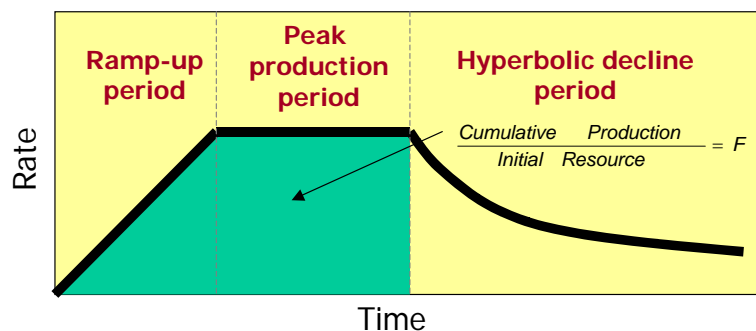
Source: ICF Consulting

Gas (plus lease condensate) production is calculated based on gas resource and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Field Abandonment

All wells in a field are assumed to be shut -in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource is for each field corresponds to the field size class as specified in Table 3D-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 3D-13). The production profile is also the same as that of an undiscovered field (Figure 3D-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2007 are shown in Table 3D-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field includes location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3D-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3D-5). Production will decline using a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3D-9. Associated-dissolved gas and lease condensate production is determined the same way as in the undiscovered field component.

Table 3D-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
Neptune	AT575	6220	1995	13	182	2008
Tahiti	GC640	4292	2002	15	691	2008
Mirage	MC941	3927	1998	12	89	2008
Telemark	AT063	4457	2000	12	89	2009
Mendoza	EB300	2000	2006	11	45	2009
GC238/GC282	GC238	2386	2001	13	182	2009
Shenzi	GC653	4238	2002	14	372	2009
Puma	GC823	4129	2003	14	372	2009
Blind Faith	MC696	6989	2001	14	372	2009
Thunder Hawk	MC734	5724	2004	13	182	2009

Table 3D-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
Thunder Horse	MC778	5993	1999	17	2954	2009
Morgus	MC942	3960	1998	11	45	2009
Silvertip	AC815	9226	2004	11	45	2010
Gotcha	AC856	7600	2006	11	45	2010
Great White	AC857	8717	2002	14	372	2010
Tobago	AC859	9493	2004	11	45	2010
Trident	AC903	9743	2001	13	182	2010
Sturgis	AT182	3710	2003	12	89	2010
EB197	EB197	1249	2004	11	45	2010
Shiner Deep	GB700	4542	2003	11	45	2010
Entrada	GB782	4690	2000	14	372	2010
Hornet	GC379	3878	2001	13	182	2010
Goose	MC751	1624	2002	12	89	2010
Thunder Horse North	MC776	5660	2000	15	691	2010
Cascade	WR206	8143	2002	14	372	2010
Chinook	WR469	8831	2003	14	372	2010
Knotty Head	GC512	3557	2005	14	372	2011
Daniel Boone	GC646	4230	2004	11	45	2011
GC767	GC767	5116	2004	11	45	2011
Ringo	MC546	2460	2006	14	372	2011
Tubular Bells	MC726	4334	2003	12	89	2011
Claymore	AT140	3725	2006	11	45	2012
Gretchen	GC114	2506	1999	9	12	2012
Clipper	GC299	3452	2005	11	45	2012
Pony	GC468	3497	2006	13	182	2012
Redrock	MC204	3334	2006	11	45	2012
La Femme	MC427	5800	2004	12	89	2012
Hawkes	MC509	4082	2001	11	45	2012
Stones	WR508	9556	2005	12	89	2012
Tiger	AC818	9004	2004	12	89	2013
Norman	GB434	5000	2006	15	691	2013
Thunder Bird	MC819	5673	2006	11	45	2013
Jack	WR759	6963	2004	14	372	2013
Grand Cayman	GB517	5000	2006	13	182	2014
Caesar	GC683	4457	2006	11	45	2014
Daredevil	LL095	9112	2005	11	45	2014
St. Malo	WR678	7036	2003	14	372	2014
Kaskida	KC292	5860	2006	15	691	2015
Egmont	MC413	2500	2006	13	182	2015
Big Foot	WR029	5235	2006	12	89	2015

Figure 3D-4. Production Profile for Producing Fields - Constant Production Case
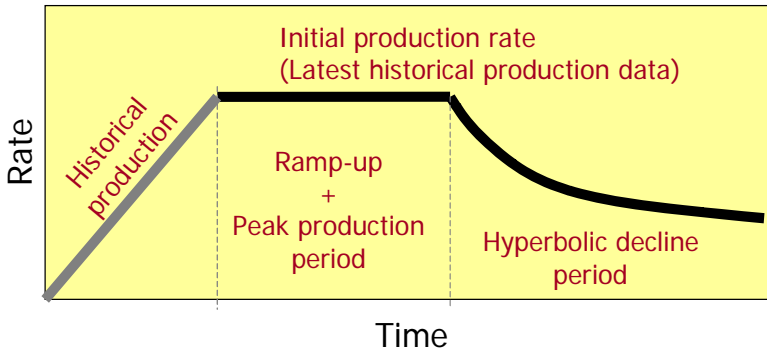
Source: ICF Consulting

Figure 3D-5. Production Profile for Producing Fields - Declining Production Case
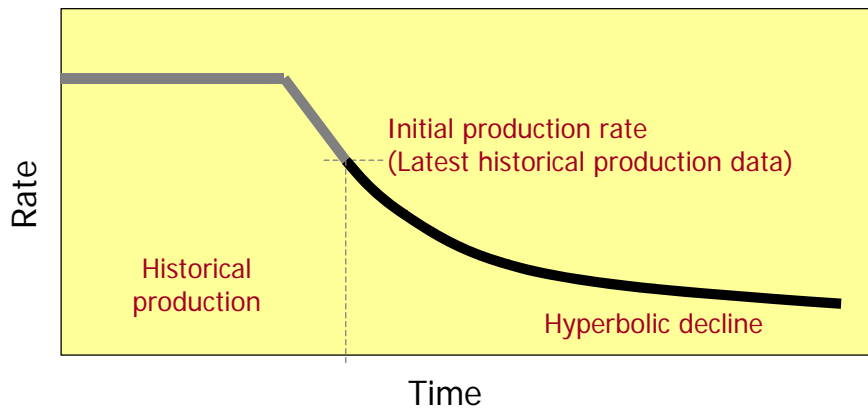
Source: ICF Consulting

Table 3D-9. Production Profile Data for Oil & Gas Producing Fields

Region	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	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in the given year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration as described in Chapter 3. In each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as:

$$\text{RESOFF}_{r,k,t+1} = \text{RESOFF}_{r,k,t} - \text{PRDOFF}_{r,k,t} + \text{NRDOFF}_{r,k,t} + \text{REVOFF}_{r,k,t} \tag{3D-17}$$

where,

RESOFF	=	beginning- of-year reserves
PRDOFF	=	production
NRDOFF	=	new reserve discoveries
REVOFF	=	reserve extensions, revisions, and adjustments
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=nonassociated gas)
t	=	year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$\text{NRDOFF}_{r,k,t} = \text{NFDISC}_{r,k,t-1} * \left(\frac{1}{\text{RSVGRO}_k} \right) \tag{3D-18}$$

$$\text{NIRDOFF}_{r,k,t} = \text{NFDISC}_{r,k,t-1} * \left(1 - \frac{1}{\text{RSVGRO}_k} \right) \tag{3D-19}$$

where,

NRDOFF	=	new reserve discovery
NIRDOFF	=	new inferred reserve additions
NFDISC	=	new field discoveries
RSVGRO	=	reserves growth factor (8.2738 for oil and 5.9612 for gas)
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=gas)
t	=	year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation)

wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, then the reserves need to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Reconfiguring Equation 3D-1 to solve for REVOFF gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \qquad (3D-20)$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base.

Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3D-10.

Table 3D-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3-E. Oil Shale Supply Submodule (OSSS)

Introduction

Oil shale rock contains a hydrocarbon known as kerogen, [1] which can be processed into a synthetic crude oil (syncrude). During the 1970s and early 1980s, the petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. One approach, which the majority of the oil companies pursued, mines the oil shale rock in underground mines, followed by surface facility retorting of the rock to create bitumen, which is then be further processed into syncrude. Occidental Petroleum Corp. pursed the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, and then the remaining underground rock would be "rubblized" using explosives to create large caverns filled with oil shale rock. The oil shale rock would then be set on fire to cause the kerogen to convert into bitumen, and the bitumen would then be pumped to the surface for further processing into syncrude. The latter approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because of the presence of underground bitumen and other petroleum compounds might contaminate underground aquifers.

A completely in-situ oil shale process is currently being experimentally tested by Shell Oil Co., wherein the oil shale rock is directly heated using heat injection wells, while petroleum products[2] are produced from separate production wells. The in-situ process has substantial environment and cost benefits relative to the other 2 approaches. The environmental benefits are primarily much lower water usage and much less land disturbance, along with an absence of oil shale waste piles on the surface. Other advantages of the in-situ process are: 1) it can access deeper oil shale resources, 2) it produces more oil and gas per acre because the process uses the entire resource column and not just the richest portion of the resource column, and 3) it directly produces petroleum products rather than a synthetic crude oil, which requires more processing at a refinery. The cost benefit is that the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Moreover, the in-situ process reduces the capital risk by building self-contained modular production units, which can then be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been fully demonstrated, there is already a substantial body of evidence from field testing conducted by Shell Oil Co. that the in-situ process is technologically feasible.[3] The current Shell field research program is expected to conclude around 2010 with the construction of a small scale demonstration plant expected to begin shortly thereafter.

The section is intended to document the representation of the oil shale industry in Oil and Gas Supply Module of NEMS. There are a number of technical and environmental issues, which will need to be resolved if oil shale is to become a major contributor to domestic petroleum production. On the technical side, the cost and performance of the technology will have to improve significantly over those developed in the 1970's and 1980's to become economic at prices below $60 per barrel (2004 dollars). On the environmental side, issues regarding facility water supply, rock waste disposal and remediation along with potential air and water pollution will have to be satisfactorily resolved in a manner, which does not impose exorbitant costs. The Oil Shale Supply Submodule (OSSS) only represents economic decision making. Potential environmental

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[1] Kerogen is a solid organic compound, which is also found in coal.
[2] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.
[3] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

constraints are not represented in the model. Given the considerable potential environmental impacts[4] of an oil shale industry based on 1980s technologies, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, it was assumed that only one new facility can begin construction in any specific future year, and as more facilities are built over time, the intervening time interval between each new facility declines to the point where one new facility can be built every year. The latter assumption is intended to mimic a technology penetration curve even though there is no informational basis for defining a more rigorously specified penetration rate. A full-scale facility has never been constructed nor operated for an extended period of time. Although the Canadian oil sands industry development history might be viewed as an analogous situation, it would be misleading. The first commercial Canadian oil sands facility began operating in 1967 and it took over 30 years to develop into a rapidly growing industry. This slow penetration rate was caused by low world oil prices from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[5]

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of syncrude per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[6] Consequently, the oil shale supply submodule was based on the concept that oil shale syncrude production would occur exclusively in the Rocky Mountains within the 2030 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2030.

Within the oil shale submodule, during each year of the projection, the submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's prevailing crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, then an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified within the submodule. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero, followed by whether the construction of a facility in that year is precluded by the construction constraints assumed within OSSS.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration

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[4] For example, it has been estimated that a 1 million barrel per day surface-retorting oil shale syncrude industry would produce over 500 million tons of waste rock per year and consume between 2.1 to 5.2 million barrels of water per day. Sources: Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resource Technology and Economic*, March 2004, Washington DC, page 24, and James T. Bartis, Tom LaTourrette, Lloyd Dixon, D.J. Peterson, Gary Cecchine, Rand Corporation, *Oil Shale Development in the United States: Prospects and Policy Issues*, 2005, Santa Monica, California, page 50.

[5] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[6] 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.

plants, almost all demonstration facilities employed this technology.[7] The facility parameter values and cost estimates of the OSSS are based on information reported for the Paraho Oil Shale Project.[8] 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,[9] 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 percent per year, starting in 2005. This cost reduction assumption results in oil shale production costs being 22 percent lower in 2030 relative to the initial 2005 cost structure.

Although the Paraho cost structure seem unrealistic relative to the notion that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, whereas there is no information whatsoever regarding the expected cost of the in-situ process. Moreover, even though the in-situ process is expected to be cheaper per barrel of output than the Parado process, this should be weighted against the fact that 1) oil and gas drilling costs have increased dramatically over the last 5 years, somewhat narrowing that cost difference, and 2) the Parado costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that a Parado-like project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volume of natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative 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, and transported offsite, while the electricity consumed on site is purchased from the local power grid. This means that both the natural gas and the electricity are valued in the Net Present Value of the cash flow calculations at their respective regional prices , which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[10]

Paraho Oil Shale Facility Configuration and Costs

Because the cost parameters reported for the Paraho Oil Shale Project are reported in 1976 dollars, all costs were inflated to 2004 dollar values. The Paraho facility parameters are as follows, with the text in parentheses indicating the variable name in the submodule.

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[7] 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.

[8] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[9] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[10] This Colorado/Utah/Wyoming region enjoys relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbitiminous coal, and 2) because the cost of existing electricity generation equipment is inherently lower than new generation equipment, because of the inflation and depreciation effects over time.

Table 3E-1. Paraho Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSM Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	100,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	25 years[11]
Facility construction time	OS_PRJ_CONST	5 year
Surface facility capital costs	OS_PLANT_INVEST	$3.2 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$400 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value

The construction lead time for oil shale facilities is assumed to be 5 years, based on construction time estimates developed for the Paraho Project.[12] Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output. In an effort to mimic the fact that an in-situ oil shale process is most likely to be developed rather than underground mining and surface retorting process, the facility linearly ramps up production over a 5 year period (i.e., 20 percent per year).[13]

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2030, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

A Paraho oil shale facility produces natural gas and consumes electricity. The parameters provided below represent the level of annual gas production and annual electricity consumption for a 100,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[14]

Table 3E-2. Paraho Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

Facility Parameters	OSSM Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	32.25 billion cubic feet per year
Electricity consumption	OS_ELEC_CONSUMP	1.66 billion kilowatt-hours per year

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation, which is then discounted to a net present value. In those years in which the net present value exceeds zero,

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[11] The facility's operational period was extended from 20 years to 25 years for the AEO2008 projections to take into account the 5-year ramp-up to full production. A discussion of this and other parameter changes in the OSSS for the AEO2008 is discussed in an EIA/OIAF/OGD memorandum to Andy Kydes from Philip Budzik, entitled: "Oil Shale Project Size and Production Ramp-Up," dated November 16, 2007.
[12] An in-situ facility would also require about five years before initial production began. Ibid.
[13] Ibid.
[14] Op. cit. Noyes Data Corporation.

then a new oil shale facility can be constructed, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 30 year period, composed of 5 years for construction and 25 years for plant operations. During the first 5 years of the 30-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 5 years. In the sixth year, the plant goes into partial operation, and produces 20 percent of the rated output. So in the sixth year revenues and operating expenses are assumed to be 20 percent of their full-production values. In years 7, 8, and 9, the plant output increases an additional 20 percent per year, while operating expenses increase by the same proportion each year. In years 10 through 30, the plant operates at its maximum utilization rate. During years 10 through 30, total revenues equal oil revenues plus natural gas revenues.[15]

Oil revenues are calculated based on current year oil prices. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil at that time and is <u>not</u> based either on historical price trends or future expected prices. Oil revenues per plant are calculated as follows:

$$(3E-1)$$
$$OIL\_REVENUE_t = OIT\_WOP(t,1) * (1.083/0.732) * OS\_PRJ\_SIZE * OS\_CAP\_FACTOR * 365$$

where,

$OIT\_WOP(t,1)$	=	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
OS_PROJ_PRJ_SIZE	=	Facility project size in barrels per day
OS_CAP_FACTOR	=	Facility capacity factor
365	=	Days per year.

During year 10 through 30, natural gas revenues are calculated as follows:

$$(3E-2)$$
$$GAS\_REVENUE_t = OS\_GAS\_PROD * OGPRCL48_t(5,3,1) * (1.083/.732) * OS\_CAP\_FACTOR$$

where,

OS_GAS_PROD	=	Annual natural gas production for 100,000 barrel per day facility
$OGPRCL48_t(5,3,1)$	=	Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

During year 10 through 30, electricity consumption costs are calculated as follows:

$$ELEC\_COST_t = OS\_ELEC\_CONSUMP * PELIN(8,t) * (1.083/.732) * 0.003412 *$$
$$OS\_CAP\_FACTOR$$
$$(3E-3)$$

where,

---

[15] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 100,000 barrel per day oil shale syncrude facility.

OS_ELEC_CONSUMP	=	Annual electricity consumption for a 100,000 barrel per day facility
PELIN(8,t)	=	Electricity price in Colorado/Utah/Wyoming at time t
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \qquad (3E\text{-}4)$$

where,

$TOT\_REVENUE_t$	=	Total project revenues at time t
TOT_COST_t	=	Total project costs at time t.

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \qquad (3E\text{-}5)$$

While total project costs are calculated as follows:

$$(3E\text{-}6)$$
$$TOT\_COST_t = OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST + ELEC\_COST_t + INVEST$$

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
$INVEST$	=	Annual surface facility investment costs.

While the plant is under construction (in years 1 through 5) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (in years 6 through 30), the capital costs (INVEST) are zero, while the other four cost elements take on positive values. The annual investment cost for the five years of construction assumes that the construction costs are evenly spread over the 5-year construction period and is calculated as follows:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \qquad (3E\text{-}7)$$

Because the plant output is composed of both shale oil syncrude and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \qquad (3E\text{-}8)$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$(3E-9)$$

$$PRJ\_MINE\_COST = (OS\_MINE\_CST\_TON*(42/(OS\_GALLON\_TON*OS\_CONV\_EFF)))*$$
$$(OS\_PROJ\_SIZE*OS\_CAP\_FACTOR*365)$$

where,

$$42 \quad = \quad \text{gallons per barrel}$$
$$365 \quad = \quad \text{days per year.}$$

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:

$$CASH\_FLOW_t = (PRETAX\_CASH\_FLOW_t*(1-OS\_CORP\_TAX\_RATE)) +$$
$$(OS\_CORP\_TAX\_RATE*OS\_PLANT\_INVEST/OS\_PRJ\_LIFE)$$

$$(3E-10)$$

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 3E-3. Discount Rate Financial Parameters

Financial Parameters	OSSM Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	70 percent
Facility equity beta	OS_EQUITY_VOL	1.75
Expected market risk premium	OS_EQUITY_PREMIUM	6.75 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is a project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. In 2005, a median beta for oil and gas field exploration service firms was 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.75.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.75 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in Ba range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$
\begin{aligned}
OS\_DISCOUNT\_RATE_t = (((& 1 - OS\_EQUITY\_SHARE) * (MC\_RMCORPBAA_t / 100 + \\
& OS\_DEBT\_PREMIUM)) * (1 - OS\_CORP\_TAX\_RATE) + \\
& (OS\_EQUITY\_SHARE * ((OS\_EQUITY\_PREMIUM * \\
& OS\_EQUITY\_VOL) + MC\_RMGFCM\_10NS_t / 100))
\end{aligned}
$$

(3E-11)

where,

OS_EQUITY_SHARE	=	Equity share of total facility capital
$MC\_RMCORPBAA_t / 100$	=	BAA corporate bond rate
OS_DEBT_PREMIUM	=	Facility debt risk premium
OS_CORP_TAX_RATE	=	Corporate income tax rate
OS_EQUITY_PREMIUM	=	Expected market risk premium
OS_EQUITY_VOL	=	Facility equity volatility beta
$MC\_RMGFCM\_10NS_t / 100$	=	10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$
OS\_DISCOUNT\_RATE_t = ((1.0 + OS\_DISCOUNT\_RATE_t) / (1.0 + INFL_t)) - 1.0 \tag{3E-12}
$$

where,

$$INFL_t \quad = \quad \text{Inflation rate at time t.}$$

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

(3E-13)

$$
NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE + OS\_PRJ\_CONST} \left[CASH\_FLOW_t * \left[\frac{1}{1 + OS\_DISCOUNT\_RATE_t} \right]^t \right]
$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Construction Timing Constraints

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are two constraints to further oil shale facility construction. The first constraint on oil shale facility construction is imposed by the absence of a Federal land leasing program for commercial oil shale facilities. The second constraint on oil shale facility construction is the financial and technical risk of building a full-scale commercial oil shale syncrude production facility. The following discussion describes which of these two constraints determines the earliest possible date for a commercial oil shale facility within the OSSS.

The highest grade oil shale resources are located on Federal land located in Colorado, Utah, and Wyoming, where these three States meet. So, Federal land is the most desirable location for siting commercial oil shale facilities. The U.S. Department of Interior, Bureau of Land Management (BLM), however, must first implement a commercial oil shale facility leasing program before commercial oil shale syncrude facilities can be built on Federal land.[16] The OSSS assumes that a BLM leasing program, including the award of Federal oil shale leases will be accomplished by 2009, so that the first commercial plant could begin construction in 2010. This BLM leasing schedule assumes that between 2 to 3 years will be required to complete the final environmental impact statement and that an additional 1 to 2 years are required to complete the first oil shale land lease auction. Of course, if the draft environmental impact statement faces significant Court challenges, the completion of the first BLM auction could occur well after 2009. Although the BLM could have a commercial oil shale lands leasing program in place by 2010 or shortly thereafter, this leasing process is not the primary constraint to building the first commercial oil shale facility.

The binding constraint to first commercial production is the rate at which field testing can be conducted and concluded so as to reduce the technical and financial risks associated with oil shale production. In June of 2005, the BLM solicited requests for oil shale RD&D leases. Each oil shale RD&D lease nomination encompasses a 160-acre tract and associated preference rights to an additional contiguous area of 4,960 acres to be reserved for a preferential right to convert to a commercial lease at a future time after additional BLM review. In 2006 and 2007, the BLM awarded 4 RD&D leases with 3 in Colorado and 1 in Utah. Of the four leases, only one will employ surface retorting using previously mined oil shale, while the other three leases employ variations of the in-situ process approach.

Because Shell's in-field research program began in 1997 on private land, the Shell oil shale RD&D program is considered to be the most advanced, and Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility, by 2010. Around 2010, Shell expects to build a non-commercial demonstration plant that would test the commercial feasibility of the in-situ process. The permitting, planning, and construction of a demonstration plant will take approximately 2 years. Another 5 years is required to complete one production cycle on one or more parcels of land. This 7-year demonstration plant process in conjunction with a 2010 starting date results in the earliest possible initiation of a full-scale commercial plant being 2017.[17]

New technology penetration is constrained by financial and technical risks. The financial risks are largely determined by the size of the investment (relative to the size of the corporation), the length of the construction period (with longer construction periods potentially resulting in significant market changes since construction began), and by the product's price volatility. The technical risks include: low production rates to due

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[16] On June 9, 2005, BLM published a Federal Register notice (page 33753) soliciting nominations for oil shale research, development and demonstration leases.

[17] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up."

technology failures, equipment breakdowns, construction cost overruns, lower than expected production rates, etc. Because the risk of employing a new untested technology is considerably greater than that associated with well established technologies, industry participants often take a wait-and-see approach, in which they hope to learn from an early implementer's mistakes and improvements. Consequently, technology penetration is slow after the new technology first becomes available, followed by a subsequent acceleration of its penetration after the technology has been perfected and proven.

In order to mimic the initially slow market penetration, followed by increasing rate of penetration, the OSSS implements a technology penetration algorithm, which specifies that 5 years must pass since the first facility began construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility began construction. This technology penetration algorithm implicitly assumes that only a single oil shale plant can begin construction in any future year. Under the oil price scenarios used in the *Annual Energy Outlook 2006* the single facility per year assumption is realistic given that oil shale only becomes economic in the high price case, such that the first plant begins operation in 2023; the second goes into operation in 2028, the third in 2031, which is beyond the 2030 timeframe of the projections. Consequently, the 5-year, 3-year, 2-year, 1-year construction delay algorithm is more constraining than the single plant per year assumption.[18]

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970's and early 1980's, the complete absence of any 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 1970's, then the prospects for oil shale development remain weak through 2030. However, technological progress can totally alter the economic and environmental landscape in ways currently unanticipated. For example, if the Shell Oil in-situ process were to be demonstrated to be both technically and economically feasible, it would significantly improve the prospects for an oil shale industry, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

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[18] Alternatively, one can view the fact that OSSS assumes a the large commercial plant size of 100,000 barrels per day to indicate the possibility that smaller oil shale facilities (e.g., 50,000 barrels per day) are initiated at a more rapid penetration rate.

Appendix A. Data Inventory

An inventory of OGSM variables is presented in the following tables. These variables are divided into four categories:

Variables: Variables calculated in OGSM
Data: Input data
Parameters: Estimated parameters
Output: OGSM outputs to other modules in NEMS.

The data inventory for the Offshore Supply Submodule is presented in a separate table.

All regions specified under classification are OGSM regions unless otherwise noted.

Equation Number	Subroutine	Variable Name		Description	Unit	Classification
		Code	**Text**			
1	OG_DCF	CF	NCFON	Net cash flow for a representative project	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
2, 5	OG_DCF	DCFTOT	PROJDCFON	Discounted cash flow for a representative project	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
3, 4, 6	OG_DCF	OG_DCF	DCFON	Discounted cash flow for a representative well	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
7, 8	OGEXP_CALC	SODCF	ODCFON	Discounted cash flow for oil	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions
7, 9	OGEXP_CALC	SGDCF	SGDCFON	Discounted cash flow for shallow gas	1987$	Class(Exploratory,Developmental); 6 Lower 48 onshore regions
10	OGEXP_CALC	CASHFLOW	CASHFLOW	Industry cash flow	1997$	NA
11	OGEXP_CALC	WELLSL48	WELLSON	Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
12	OGEXP_CALC	SUCWELLL48	SUCWELSON	Successful Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
13	OGEXP_CALC	DRYWELLL48	DRYWELON	Dry Lower 48 onshore wells drilled	Wells	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
14	OGCST_L48	ESTOWELLSL48	ESTOWELLS	Estimated lower 48 onshore oil drilling (successful and dry)	Wells	Lower 48 onshore
15	OGCST_L48	ESTGWELLSL48	ESTGWELLS	Estimated lower 48 onshore gas drilling (successful and dry)	Wells	Lower 48 onshore
16	OGCST_L48	RIGSL48	RIGSL48	Available rigs	Rigs	Lower 48 onshore
17	OGCST_L48	DRILLL48	DRILLCOST	Successful well drilling costs	1987$ per well	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
18	OGCST_L48	DRYL48	DRYCOST	Dry well drilling costs	1987$ per well	Class(Exploratory,Developmental);

Equation Number	Subroutine	Variables		Description	Unit	Classification
		Variable Name				
		Code	**Text**			
						6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
19	OGCST_L48	LEASL48	LEQC	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
20	OGCST_L48	OPERL48	OPC	Operating costs	1987$ per well	Class(Exploratory,Developmental); 6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
21	OGOUT_L48	FR1L48	FR1	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions; Fuel(2 oil,2 gas)
22	OGOUT_L48	NRDL48	NRD	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF	6 Lower 48 onshore regions; Fuel(2 oil,2 gas);
23	OGOUT_L48	FR2L48	FR2	Finding rates for other exploratory	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions; Fuel(2 oil,2 gas)
24	OGOUT_L48	FR3L48	FR3	Finding rates for developmental wells	Oil-MMB per well Gas-BCF per well	6 Lower 48 onshore regions; Fuel(2 oil,2 gas)
25	OGOUT_L48	RESADL48	RA	Total additions to proved reserves	Oil-MMB Gas-BCF	6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
26	OGOUT_L48	RESBOYL48	R	End of year reserves for current year	Oil-MMB Gas-BCF	6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
27-28	OGOUT_L48	PRRATL48	PR	Production to reserves ratios	Fraction	6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
29	OGOUT_L48	EXPRDL48	Q	Production	Oil-MMB Gas-BCF	6 Lower 48 onshore regions; Fuel(2 oil, 5 gas)
30	OGCOMP_AD	X	X	Associated-dissolved gas reserves to production ratio in logistic form	Fraction	6 Lower 48 onshore regions
31	OGCOMP_AD	PR_ADGAS	PR_ADGAS	Associated-dissolved gas production to reserves ratio	Fraction	6 Lower 48 onshore regions
32	OGCOMP_AD	RA_ADGAS	RA_ADGAS	Associated-dissolved gas reserve additions	BCF	6 Lower 48 onshore regions
33	OGCOMP_AD	R_ADGAS	R_ADGAS	Associated-dissolved gas reserves	BCF	6 Lower 48 onshore regions

		Variables				
		Variable Name				
Equation Number	**Subroutine**	**Code**	**Text**	**Description**	**Unit**	**Classification**
34	OGCOMP_AD	OGPRDAD	Q_ADGAS	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions
35	OGCOST_AK	DRILLAK	DRILLCOST	Drilling costs	1987$ per well	Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas)
36	OGCOST_AK	LEASAK	EQUIP	Lease equipment costs	1987$ per well	Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas)
37	OGCOST_AK	OPERAK	OPCOST	Operating costs	1987$ per well	Class(Exploratory,Developmental); 3 Alaska regions,Fuel (oil, gas)
38	OG_DCF	REV	REV	Revenue from a representative project	1987$	Alaska field
39	OG_DCF	DCFTOT	DCF	Discounted cash flow for a representative project	1987$	Alaska field
40	OGNEW_AK	COST_AK	COST	Capital costs	1987$	Alaska field
41	OGNEW_AK	PROF_AK	PROF	Profitability indicator	NA	Alaska field
42	XOGOUT_IMP	SUCWELL	SUCWELL	Successful conventional Canadian wells drilled in WCSB	Wells	Fuel(gas)
43	XOGOUT_IMP	FRCAN	FRCAN	Canadian finding rate for WCSB, conventional only	Gas:BCF per well	Fuel(gas)
44	XOGOUT_IMP	URRCAN	URRCAN	Canadian remaining WCSB conventional resources	Gas Bcf	Fuel(gas)
45	XOGOUT_IMP	RESADCAN	RESADCAN	Conventional Canadian reserve additions in WCSB	Gas: BCF	Fuel(gas)
46	XOGOUT_IMP	RESBOYCAN	RESBOYCAN	Conventional Canadian reserves in WCSB (BOY for t+1)	Gas: BCF	Fuel(gas)
47	XOGOUT_IMP	PRRATCAN	PRRATCAN	Conventional Canadian production to reserves ratio in WCSB	Fraction	Fuel(gas)
3A-1	OG_DCF	DCFTOT	DCF	Discounted cash flow for a representative project	1987$ per project	NA
3A-2	OG_DCF	PVSUM(1)	PVREV	Present value of expected	1987$ per project	NA

		Variables				
		Variable Name				
Equation Number	Subroutine	Code	Text	Description	Unit	Classification
				revenue		
3A-4	OG_DCF	PVSUM(2)	PVROY	Present value of expected royalty payments	1987$ per project	NA
3A-5	OG_DCF	PVSUM(3)	PVPRODTAX	Present value of expected production taxes	1987$ per project	NA
3A-6	OG_DCF	PVSUM(4)	PVDRILLCOST	Present value of expected drilling costs	1987$ per project	NA
3A-7	OG_DCF	PVSUM(5)	PVEQUIP	Present value of expected lease equipment costs	1987$ per project	NA
3A-8	OG_DCF	PVSUM(8)	PVKAP	Present value of expected capital costs	1987$ per project	NA
3A-9	OG_DCF	PVSUM(6)	PVOPCOST	Present value of expected operating costs	1987$ per project	NA
3A-10	OG_DCF	PVSUM(7)	PVABANDON	Present value of expected abandonment costs	1987$ per project	NA
3A-11	OG_DCF	PVSUM(13)	PVTAXBASE	Present value of expected tax base	1987$ per project	NA
3A-12	OG_DCF	XIDC	XIDC	Expensed Costs	1987$ per project	NA
3A-14	OG_DCF	DHC	DHC	Dry hole costs	1987$ per project	NA
3A-15	OG_DCF	DEPREC	DEPREC	Depreciable costs	1987$ per project	NA
3A-16	OG_DCF	PVSUM(15)	PVSIT	Expected value of state income taxes	1987$ per project	NA
3A-17	OG_DCF	PVSUM(16)	PVFIT	Expected value of federal income taxes	1987$ per project	NA
3D-1	DeterminePossibleExplorationProjects	CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
3D-2	DeterminePossibleExplorationProjects	SC	γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
3D-3	DeterminePossibleExplorationProjects	CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
3D-4	EXPLCOST	EXPLCOST	ExplorationDrilling	Exploration well drilling cost	$ per wells	Offshore evaluation unit

Equation Number	Subroutine	Variables		Description	Unit	Classification
		Variable Name				
		Code	**Text**	**Description**	**Unit**	**Classification**
			Costs			
3D-5	EXPLCOST	EXPLCOST	ExplorationDrilling Costs	Exploration well drilling cost	$ per wells	Offshore evaluation unit
3D-6	EXPLCOST	EXPLCOST	ExplorationDrilling Costs	Exploration well drilling cost	$ per structure	Offshore evaluation unit
3D-7	PFCOST	PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
3D-8	PFCOST	PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
3D-9	PFCOST	PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
3D-10	PFCOST	PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
3D-11	PFCOST	PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
3D-12	PFCOST	PFCOST	SubseaTemplateCost	Subsea Template Cost	$ per template	Offshore evaluation unit
3D-13	DEVLCOST	DEVLCOST	DevelopmentDrillingCost	Development drilling cost	$ per well	Offshore evaluation unit
3D-14	DEVLCOST	DEVLCOST	DevelopmentDrillingCost	Development drilling cost	$ per well	Offshore evaluation unit
3D-15	OPRCOST	OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
3D-16	OGINIT_OFF	NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
3D-17	OGReportToOGSM	RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
3D-18	OGReportToOGSM	NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
3D-19	OGReportToOGSM	NIRDOFF	NIRDOFF	Offshore new inferrred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
3D-20	OGReportToOGSM	REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well	Offshore region; Offshore fuel(oil,gas)

Variables						
Equation Number	**Subroutine**	**Variable Name**		**Description**	**Unit**	**Classification**
		Code	**Text**			
					Gas-BCF per well	

Data						
Variable Name		**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
Code	**Text**					
ACCESS_YR	--	OGINIT_BFW	Year in which Federal access restrictions would be reduced in the Rocky Mountain Region in an increased ACCESS Case	Year	NA	Office of Integrated Analysis and Forecasting
ADVLTXL48	PRODTAX	OGFOR_L48 OGINIT_L48	Lower 48 onshore ad valorem tax rates	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7
ADVLTXOFF	PRODTAX	OGFOR_OFF OGINIT_OFF	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7
ANGTSMAX	--	OGINIT_AK OGPIP_AK	ANGTS maximum flow	BCF/D	Alaska	National Petroleum Council
ANGTSPRC	--	OGINIT_AK OGPIP_AK	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	National Petroleum Council
ANGTSRES	--	OGINIT_AK OGPIP_AK	ANGTS reserves	BCF	Alaska	National Petroleum Council
ANGTSYR	--	OGINIT_AK OGPIP_AK	Earliest start year for ANGTS flow	Year	NA	National Petroleum Council
BUILDLAG	--	OGEXPAND_LNG OGINIT_LNG	Buildup period for expansion of LNG facilities	Year	NA	Office of Integrated Analysis and Forecasting
CPRDL48	COPRD	OGFOR_L48 OGINIT_L48	Lower 48 onshore coproduct rate	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
CPRDOFF	COPRD	OGFOR_OFF OGINIT_OFF	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions;	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
					Fuel (oil, gas)	
CURPRRCAN	PR	OGINIT_IMP OGOUT_IMP	Canadian 1989 P/R ratio	Fraction	Canada; Fuel (gas)	Derived using data from the Canadian Petroleum Association
CURPRRL48	omega	OGINIT_L48 OGINIT_RES OGOUT_L48	Lower 48 initial P/R ratios	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
CURPRROFF	omega	OGINIT_OFF OGINIT_RES OGOUT_OFF	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
CURPRRTDM	--	OGINIT_L48 OGOUT_L48	Lower 48 initial P/R ratios at NGTDM level	Fraction	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
CURRESL48	R	OGINIT_L48 OGINIT_RES OGOUT_L48	Lower 48 onshore initial reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Derived from Annual Reserves Report Data
CURRESOFF	R	OGINIT_OFF OGINIT_RES OGOUT_OFF	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Derived from Annual Reserves Report Data
CURRESTDM	--	OGINIT_L48 OGINIT_RES OGOUT_L48	Lower 48 natural gas reserves at NGTDM level	MMB BCF	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
DECFAC	DECFAC	OGOUT_L48	Inferred resource simultaneous draw down decline rate adjustment factor	Fraction	NA	Office of Integrated Analysis and Forecasting
DECLL48	--	OGFOR_L48 OGINIT_L48 WELL	Lower 48 onshore decline rates	Fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
DECLOFF	--	OGFOR_OFF OGINIT_OFF WELL	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
DECLPRO	--	OGINIT_AK OGPRO_AK	Alaska decline rates for currently producing fields	Fraction	Field	Office of Integrated Analysis and Forecasting
DEPLETERT	--	OGINIT_IMP	Depletion rate	Fraction	NA	Not Used Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
DEV_AK	--	OGDEV_AK OGINIT_AK OGSUP_AK	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
DISC	disc	OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW	Discount rate	Fraction	National	Office of Integrated Analysis and Forecasting
DRILLAK	DRILL	OGCOST_AK OGINIT_AK	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
DRILLOFF	DRILL	OGALL_OFF OGFOR_OFF OGINIT_OFF	Offshore drilling cost	1987$	4 Lower 48 offshore subregions	Mineral Management Service
DRLNFWAK	--	OGCOST_AK OGINIT_AK	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
DRYAK	DRY	OGDCF_AK OGDEV_AK OGINIT_AK OGNEW_AK	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
DRYOFF	DRY	OGALL_OFF OGEXP_CALC OGFOR_OFF OGINIT_OFF	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Management Service
DVWELLOFF	--	OGFOR_OFF OGINIT_OFF	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)	Minerals Management Service
DVWLCBML48	--	OGFOR_L48 OGINIT_L48	Lower 48 development project drilling schedules for coalbed methane	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
DVWLDGSL48	--	OGFOR_L48 OGINIT_L48	Lower 48 development project drilling schedules for deep gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
DVWLDVSL48	--	OGFOR_L48 OGINIT_L48	Lower 48 development project drilling schedules for devonian shale	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
DVWLOILL48	--	OGFOR_L48 OGINIT_L48	Lower 48 development project drilling schedules for oil	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
DVWLSGSL48	--	OGFOR_L48 OGINIT_L48	Lower 48 development project drilling schedules for shallow gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
DVWLTSGL48	--	OGFOR_L48 OGINIT_L48	Development project drilling schedules for tight gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
ELASTL48	--	OGINIT_L48 OGINIT_RES OGOUT_L48	Lower 48 onshore production elasticity values	Fraction	6 OGSm Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
ELASTOFF	--	OGINIT_OFF OGINIT_RES OGOUT_OFF	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions	Office of Integrated Analysis and Forecasting
EMCO	--	OGCOMP_EMIS OGINIT_EMIS	Emission factors for crude oil production	Fraction	Census regions	EPA - Energy Technology Characterizations Handbook
EMFACT	--	OGCOMP_EMIS OGINIT_EMIS	Emission factors	MMB MMCF	Census regions	EPA - Energy Technology Characterizations Handbook
EMNG	--	OGCOMP_EMIS OGINIT_EMIS	Emission factors for natural gas production	Fraction	Census regions	EPA - Energy Technology Characterizations Handbook
EQUIPAK	EQUIP	OGCOST_AK OGINIT_AK	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	U.S. Geological Survey
EXOFFRGNLAG	--	OGEXP_CALC OGINIT_BFW	Offshore exploration & development regional expenditure (1989)	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Office of Integrated Analysis and Forecasting
EXP_AK	--	OGDEV_AK OGINIT_AK OGSUP_AK	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	Office of Integrated Analysis and Forecasting
EXWELLOFF	--	OGFOR_OFF OGINIT_OFF	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions	Minerals Management Service
EXWLCBML48	--	OGFOR_L48 OGINIT_L48	Lower 48 exploratory project drilling schedules for coalbed methane	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
EXWLDGSL48	--	OGFOR_L48	Lower 48 exploratory and	wells per year	6 Lower 48 onshore	Office of Integrated Analysis and

	Data					
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
		OGINIT_L48	developmental project drilling schedules for deep gas		regions	Forecasting
EXWLDVSL48	--	OGFOR_L48 OGINIT_L48	Lower 48 exploratory project drilling schedules for devonian shale	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
EXWLOILL48	--	OGFOR_L48 OGINIT_L48	Lower 48 exploratory project drilling schedules for oil	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
EXWLSGSL48	--	OGFOR_L48 OGINIT_L48	Lower 48 exploratory project drilling schedules for shallow gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
EXWLTSGL48	--	OGFOR_L48 OGINIT_L48	Lower 48 exploratory project drilling schedules for tight gas	wells per year	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
FACILAK	--	OGDEV_AK OGFAC_AK OGINIT_AK OGSUP_AK	Alaska facility cost (oil field)	1990$/bls	Field size class	U.S. Geological Survey
FEDTXR	FDRT	OGDCF_AK OGEXP_CALC OGFOR_L48 OGFOR_OFF OGINIT_BFW	U.S. federal tax rate	fraction	Canada	U.S. Tax Code
FLOWCAN	--	OGINIT_IMP	Canadian flow rates	bls, MCF per year	Canada; Fuel (oil, gas)	Not used. Office of Integrated Analysis and Forecasting
FLOWL48	--	OGFOR_L48 OGINIT_L48	Lower 48 onshore flow rates	bls, MCF per year	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	EIA, Office of Oil and Gas
FLOWOFF	--	OGFOR_OFF OGINIT_OFF	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
FPRDCST	--	OGINIT_LNG OGPROF_LNG	Foreign production costs	1991$/MCF per year	LNG Source Country	National Petroleum Council
FRMINL48	FRMIN	OGINIT_L48 OGOUT_L48	Lower 48 onshore minimum exploratory well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
FRMINOFF	FRMIN	OGINIT_OFF OGOUT_OFF	Offshore minimum exploratory well finding rate	MMB BCF	4 Lower 48 offshore subregions;	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	Text	Subroutine	Description	Unit	Classification	Source
				per well	Fuel (oil, gas)	
FRTECHCAN	FRTECH	XOGOUT_IMP	Canada technology factor applied to finding rate	fraction	Canada	Office of Integrated Analysis and Forecasting
FR1L48	FR1	OGINIT_L48 OGOUT_L48	Lower 48 onshore new field wildcat well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
FR1OFF	FR1	OGINIT_OFF OGOUT_OFF	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
FR2L48	FR3	OGINIT_L48 OGOUT_L48	Lower 48 onshore developmental well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
FR2OFF	FR3	OGINIT_OFF OGOUT_OFF	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
FR3L48	FR2	OGINIT_L48 OGOUT_L48	Lower 48 other exploratory well finding rate	MMB BCF per well	6 Lower 48 onshore regions; Fuel (2 oil, 2 gas)	Office of Integrated Analysis and Forecasting
FR3OFF	FR2	OGINIT_OFF OGOUT_OFF	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
FSZCOAK	__	OGFOR_AK OGINIT_AK OGNEW_AK	Alaska oil field size distributions	MMB	3 Alaska regions	U.S. Geological Survey
FSZNGAK	--	OGFOR_AK OGINIT_AK OGNEW_AK	Alaska gas field size distributions	BCF	3 Alaska regions	U.S. Geological Survey
HISTADL48	--	OGINIT_L48	Lower 48 historical associated-dissolved natural gas reserves	BCF	NA	Annual Reserves report
HISTADOFF	--	OGINIT_OFF	Offshore historical associated-dissolved natural gas reserves	BCF	NA	Annual Reserves Report
HISTFRCAN	--	OGINIT_IMP XOGOUT_IMP	Historical Canadian finding rate for gas	BCF per well	Canada	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
HISTPRDCO	--	OGINIT_AK OGPRO_AK	Alaska historical crude oil production	MB/D	Field	Alaska Oil and Gas Conservation Commission
HISTPRRCAN	--	OGINIT_IMP XOGOUT_IMP	Canadian gas production to reserves ratio for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
HISTPRRL48	--	OGINIT_L48	Lower 48 historical P/R ratios	fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Derived from Annual Reserves Report
HISTPRROFF	--	OGINIT_OFF	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Derived from Annual Reserves Report
HISTPRRTDM	--	OGINIT_L48	Lower 48 onshore historical P/R ratios at the NGTDM level	fraction	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
HISTRESAD	--	OGINIT_IMP XOGOUT_IMP	Canadian gas reserves additions for historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
HISTRESCAN	--	OGINIT_IMP XOGOUT_IMP	Canadian beginning of year gas reserves for historical years	BCF	Canada; Fuel (gas)	Canadian Petroleum Association
HISTWELCAN	--	OGINIT_IMP XOGOUT_IMP	Canadian gas wells drilled in historical years	BCF	Canada; Fuel (gas)	Office of Integrated Analysis and Forecasting
HISTRESL48	--	OGINIT_L48	Lower 48 onshore historical beginning-of-year reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Annual Reserves Report
HISTRESOFF	--	OGINIT_OFF	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Annual Reserves Report
HISTRESTDM	--	OGINIT_L48	Lower 48 onshore historical beginning-of-year reserves at the NGTDM level	MMB BCF	17 OGSM/NGTDM regions; Fuel (2 oil, 5 gas)	Annual Reserves Report
IMPBYR	--	WELL OGEXPAND_LNG OGINIT_IMP XOGOUT_IMP	Base start-year for Foreign Natural Gas Supply Submodule	--	--	Office of Integrated Analysis and Forecasting
INFL	infl	OGDCF_AK OGFOR_L48	U.S. inflation rate	fraction	National	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	Text	Subroutine	Description	Unit	Classification	Source
		OGFOR_OFF OGINIT_BFW				
INFRSVL48	I	OGINIT_L48 OGOUT_L48	Lower 48 onshore inferred reserves	MMB BCF	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
INFRSVOFF	I	OGINIT_OFF OGOUT_OFF	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
INFRT	--	OGINIT_IMP	Canadian inflation rate	fraction	Canada	Not used. Office of Integrated Analysis and Forecasting
KAPFRCAK	EXKAP	OGDCF_AK OGINIT_AK	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
KAPFRCL48	EXKAP	OGFOR_L48 OGINIT_L48	Lower 48 onshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)	U.S. Tax Code
KAPFRCOFF	EXKAP	OGFOR_OFF OGINIT_OFF	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)	U.S. Tax Code
KAPSPNDL48	KAP	OGFOR_L48 OGINIT_L48	Lower 48 onshore other capital expenditures	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Not used
KAPSPNDOFF	KAP	OGFOR_OFF OGINIT_OFF	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Mangement Service
LAGDRILL48	--	OGFOR_L48 OGINIT_L48	1989 Lower 48 drill cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
LAGDRYL48	--	OGFOR_L48 OGINIT_L48	1989 Lower 48 dry hole cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
LAGLEASL48	--	OGFOR_L48	1989 Lower 48 lease equipment	1987$	Class (exploratory,	Office of Integrated Analysis and

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
		OGINIT_L48	cost		developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Forecasting
LAGOPERL48	--	OGFOR_L48 OGINIT_L48	1989 Lower 48 operating cost	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
LEASOFF	EQUIP	OGFOR_OFF OGINIT_OFF	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Minerals Mangement Service
LIQCAP	--	OGEXPAND_LNG OGINIT_LNG	Liquefaction capacity	BCF	LNG Source Country	National Petroleum Council
LIQCST	--	OGINIT_LNG OGPROF_LNG	Liquefaction costs	1991$/MCF	LNG Source Country	National Petroleun Council
LIQSTAGE	--	OGEXPAND_LNG OGPROF_LNG	Liquefaction stage	NA	NA	National Petroleum Council
LST_CONV	--	OGINIT_BFW	Share of the conventional resources in the Rocky Mountains that are subject to Federal lease stipulations	Percent	Fuel (oil, gas)	ARI
MAXPRO	--	OGFOR_AK OGINIT_AK OGPRO_AK	Alaska maximum crude oil production	MB/D	Field	Announced Plans
MEXEXP	--	OGINIT_IMP OGOUT_MEX	Exports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
MEXIMP	--	OGINIT_IMP OGOUT_MEX	Imports from Mexico	BCF	3 US/Mexican border crossing	Office of Integrated Analysis and Forecasting
NAC_CONV	--	OGINIT_BFW	Share of the conventional resources in the Rocky Mountains that are legally inaccessible	Percent	Fuel (oil, gas)	ARI
NFW_AK	--	OGINIT_AK OGNEW_AK	Alaska drilling schedule for new field wildcats	wells	NA	Office of Integrated Analysis and Forecasting
NFWCOSTOFF	COSTEXP	OGFOR_OFF OGINIT_OFF	Offshore new field wildcat cost	1987$	Class (exploratory, developmental);	Minerals Management Service

Data						
Variable Name						
Code	Text	Subroutine	Description	Unit	Classification	Source
					4 Lower 48 offshore subregions	
NFWELLOFF	--	OGFOR_OFF OGINIT_OFF	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1	Minerals Management Service
NGTDMMAP	--	OGINIT_L48 OGINIT_RES OGOUT_L48	Mapping of NGTDM regions to OGSM regions	NA	17 OGSM/NGTDM regions	Office of Integrated Analysis and Forecasting
OGCNPPRD	--	OGINIT_PRICE	Canadian price of oil and gas	oil: 87$s/B gas: 87$s/mcf	Canada	NGTDM
OGPNGIMP	--	OGPIP_AK OGPROF_LNG	Natural gas import price	87$s/mcf	US/Canadian & US/Mexican border crossings and LNG destination points	NGTDM
OPEROFF	OPCOST	OGFOR_OFF OGINIT_OFF	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions	Mineral Management Service
PRJAK	n	OGDCF_AK OGINIT_AK	Alaska oil project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
PRJL48	n	OGFOR_L48 OGINIT_L48	Lower 48 project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
PRJOFF	n	OGFOR_OFF OGINIT_OFF	Offshore project life	Years	Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
PROYR	--	OGFOR_AK OGINIT_AK OGPRO_AK	Start year for known fields in Alaska	Year	Field	Announced Plans
QLNG	--	OGEXPAND_LNG OGINIT_LNG OGLNG_OUT	LNG operating flow capacity	BCF	LNG destination points	National Petroleum Council
QLNGMAX	--	OGEXPAND_LNG OGINIT_LNG OGLNG_OUT	LNG maximum capacity	BCF	LNG destination Points	National Petroleum Council
RCPRDAK	m	OGDCF_AK OGINIT_AK	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
RCPRDL48	m	OGFOR_L48 OGINIT_L48	Lower 48 recovery period for intangible & tangible drill cost	Years	Lower 48 Onshore	U.S. Tax Code
RCPRDOFF	m	OGFOR_OFF OGINIT_OFF	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore	U.S. Tax Code
RECRES	--	OGFOR_AK OGINIT_AK OGPRO_AK	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
REGASCST	--	OGINIT_LNG OGPROF_LNG	Regasification costs	1991$/MCF per year	Operational Stage; LNG destination points	National Petroleum Council
REGASEXPAN	--	OGEXPAND_LNG OGINIT_LNG	Regasification capacity	BCF	LNG destination points	National Petroleum Council
REGASSTAGE	--	OGEXPAND_LNG OGINIT_LNG OGPROF_LNG	Regasification stage	NA	NA	National Petroleum Council
RESBASE	Q	OGINIT_IMP XOGOUT_IMP	Canadian recoverable resource estimate	BCF	Canada	Canadian Geological Survey
ROYRT	ROYRT	OGDCF_AK OGFOR_L48 OGINIT_BFW	Alaska royalty rate	fraction	Alaska	U.S. Geological Survey
SEVTXAK	PRODTAX	OGINIT_AK OGSEVR_AK	Alaska severance tax rates	fraction	Alaska	U.S. Geological Survey
SEVTXL48	PRODTAX	OGFOR_L48 OGINIT_L48	Lower 48 onshore severance tax rates	fraction	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Commerce Clearing House
SEVTXOFF	PRODTAX	OGFOR_OFF OGINIT_OFF	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)	Commerce Clearing House
SPENDIRKLAG	--		1989 Lower 48 exploration & development expenditures	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
SRAK	SR	OGDCF_AK OGDEV_AK OGINIT_AK OGNEW_AK	Alaska drilling success rates	fraction	Alaska	Office of Oil and Gas

			Data			
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
SRL48	SR	OGEXP_CALC OGEXP_FIX OGFOR_L48 OGINIT_L48 OGOUT_L48	Lower 48 drilling success rates	fraction	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
SROFF	SR	OGALL_OFF OGFOR_OFF OGINIT_OFF OGOUT_OFF	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Minerals Management Service
STARTLAG	--	OGEXPAND_LNG OGINIT_LNG	Number of year between stages (regasification and liquefaction)	years	NA	Office of Integrated Analysis and Forecasting
STL_CONV	--	OGINIT_BFW	Share of the conventional resources in the Rocky Mountains that are subject to Standard Lease Terms	Percent	Fuel (oil, gas)	ARI
STTXAK	STRT	OGDCF_AK OGINIT_AK	Alaska state tax rate	fraction	Alaska	U.S. Geological Survey
STTXL48	STRT	OGEXP_CALC OGFOR_L48 OGINIT_L48	State tax rates	fraction	6 Lower 48 onshore regions	Commerce Clearing House
STTXOFF	STRT	OGEXP_CALC OGFOR_OFF OGINIT_L48	State tax rates	fraction	4 Lower 48 offshore subregions	Commerce Clearing House
TECHAK	TECH	OGCOST_AK OGINIT_AK	Alaska technology factors	fraction	Alaska	Office of Integrated Analysis and Forecasting
TECHL48	TECH	OGFOR_L48 OGINIT_L48	Lower 48 onshore technology factors applied to costs	fraction	Lower 48 Onshore	Office of Integrated Analysis and Forecasting
TECHOFF	TECH	OGFOR_OFF OGINIT_OFF	Offshore technology factors applied to costs	fraction	Lower 48 Offshore	Office of Integrated Analysis and Forecasting
TRANCST	--	OGINIT_LNG OGPROF_LNG	LNG transporation costs	1990/MCF	NA	National Petroleum Council
TRANSAK	TRANS	OGDCF_AK OGINIT_AK	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
TRANSL48	TRANS	OGFOR_L48 OGINIT_L48	Lower 48 onshore expected transportation costs	NA	6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Not Used
TRANSOFF	TRANS	OGFOR_OFF OGINIT_OFF	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)	Not Used
UNRESOFF	Q	OGINIT_OFF OGOUT_OFF	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
URRCRDL48	Q	OGINIT_L48 OGOUT_L48	Lower 48 onshore undiscovered recoverable crude oil resources	MMB	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
URRTDM	--	OGINIT_L48 OGOUT_L48	Lower 48 onshore undiscovered recoverable natural gas resources	TCF	6 Lower 48 onshore regions	Office of Integrated Analysis and Forecasting
WDCFIRKLAG	--	OGEXP_CALC OGINIT_BFW	1989 Lower 48 exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	Office of Integrated Analysis and Forecasting
WDCFIRLAG	--	OGEXP_CALC OGINIT_BFW	1989 Lower 48 regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 6 Lower 48 onshore regions;	Office of Integrated Analysis and Forecasting
WDCFL48LAG	--	OGEXP_CALC OGINIT_BFW	1989 Lower 48 onshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
WDCFOFFIRKLAG	--	OGEXP_CALC OGINIT_BFW	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Integrated Analysis and Forecasting
WDCFOFFIRLAG	--	OGEXP_CALC OGINIT_BFW	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;	Office of Integrated Analysis and Forecasting
WDCFOFFLAG	--	OGEXP_CALC OGINIT_BFW	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)	Office of Integrated Analysis and Forecasting
WELLAGL48	WELLSON	OGEXP_CALC	1989 Lower 48 wells drilled	Wells per	Class (exploratory,	Office of Oil & Gas

Data						
Variable Name						
Code	**Text**	**Subroutine**	**Description**	**Unit**	**Classification**	**Source**
		OGEXP_FIX OGINIT_L48		year	developmental); 6 Lower 48 onshore regions; Fuel (2 oil, 5 gas)	
WELLAGOFF	WELLSOFF	OGALL_OFF OGEXP_CALC OGINIT_OFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)	Office of Oil & Gas
XDCKAPAK	XDCKAP	OGDCF_AK OGINIT_AK	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code
XDCKAPL48	XDCKAP	OGFOR_L48 OGINIT_L48	Lower 48 intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code
XDCKAPOFF	XDCKAP	OGFOR_OFF OGINIT_OFF	Offshore intangible drill costs that must be depreciated	fraction	NA	U.S. Tax Code

Outputs					
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
OGFOR_AK OGPIP_AK	OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGINIT_RES OGOUT_L48 OGOUT_OFF	OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGOUT_EOR	OGEORCOGC	Electric cogeneration capacity from EOR	MWH	6 Lower 48 onshore regions	Industrial (not used)
OGOUT_EOR	OGEORCOGG	Electric cogeneration volumes from EOR	MWH	6 Lower 48 onshore regions	Industrial (not used)
OGCOMP_AD	OGPRDAD	Associated-dissolved gas production	BCF	6 Lower 48 onshore regions & 3 Lower 48 offshore regions	NGTDM
OGINIT_RES XOGOUT_IMP	OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGINIT_RES OGOUT_L48	OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGINIT_RES OGOUT_OFF	OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGFOR_AK OGPIP_AK OGPRO_AK	OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGINIT_IMP XOGOUT_IMP OGOUT_MEX	OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM
OGLNG_OUT XOGOUT_IMP OGOUT_MEX	OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGINIT_RES XOGOUT_IMP	OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGINIT_RES	OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower	PMM

Outputs					
OGSM Subroutine	**Variable Name**	**Description**	**Unit**	**Classification**	**Passed To Module**
OGOUT_L48 OGOUT_OFF				48 offshore regions	
OGINIT_RES OGOUT_OFF	OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGINIT_RES OGOUT_L48	OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM

	OFFSHORE OIL AND GAS SUPPLY SUBMODULE	
Parameter	**Description**	**Value**
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6
TOTFLD	Total numver of evaluation units	3600
nANN	Total number of announce discoveries	127
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

OFFSHORE OIL AND GAS SUPPLY SUBMODULE			
Variable	**Description**	**Unit**	**Source**
ann_EU	Announced discoveries - Evaluation unit name	-	OIAF
ann_FAC	Announced discoveries - Type of production facility	-	MMS
ann_FN	Announced discoveries - Field name	-	OIAF
ann_FSC	Announced discoveries - Field size class	integer	MMS
ann_OG	Announced discoveries - fuel type	-	MMS
ann_PRDSTYR	Announced discoveries - Start year of production	integer	MMS
ann_WD	Announced discoveries - Water depth	feet	MMS
ann_WL	Announced discoveries - Number of wells	integer	MMS
ann_YRDISC	Announced discoveries - Year of discovery	integer	MMS
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	MMS
cstCap	Cost of capital	percent	MMS
dDpth	Drilling depth by PA, EU, FSC	feet	MMS
deprSch	Depreciation schedule (8 year schedule)	fraction	MMS
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	MMS
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	MMS
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	wells/field/year	ICF
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	MMS
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	MMS
drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF

	OFFSHORE OIL AND GAS SUPPLY SUBMODULE		
Variable	**Description**	**Unit**	**Source**
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	MMS
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
expTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	MMS
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	OIAF
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	OIAF
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	OIAF
levExpSucRate	Seismic technology (increase exploration success rate)	percent	OIAF
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	OIAF
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	OIAF
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	OIAF
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	OIAF
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	OIAF
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF

OFFSHORE OIL AND GAS SUPPLY SUBMODULE			
Variable	**Description**	**Unit**	**Source**
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: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	MMS
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production faclity design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	MMS
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF

OFFSHORE OIL AND GAS SUPPLY SUBMODULE			
Variable	**Description**	**Unit**	**Source**
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	MMS
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	MMS
prd_ID	Producing fields - MMS field ID	-	MMS
prd_OG	Producing fields - Fuel type	-	MMS
prd_YRDISC	Producing fields - Year of discovery	year	MMS
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	OIAF
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF

OFFSHORE OIL AND GAS SUPPLY SUBMODULE			
Variable	**Description**	**Unit**	**Source**
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	MMS
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	MMS
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	MMS
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	MMS
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	MMS
vMean	Geometric mean MMBOE of FSC	MMBOE	MMS
vMin	Minimum MMBOE of FSC	MMBOE	MMS
wDpth	Water depth by PA, EU, FSC	feet	MMS
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF
Sources: MMS = Minerals Management Service; ICF = ICF Consulting; OIAF = EIA, Office of Integrating Analysis and Forecasting			

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
-	BASLOC	Basin Location: The basin/play name	NA	UGR Type; Play	ARI/USGS
-	PNUM	Play Number: The play number established by ARI	-	UGR Type; Play	ARI
ATUNDRLOC	ATUL	Undrilled Locations - Advanced Technology: Number of locations available to drill under advanced technology	-	UGR Type; Play; Quality[1]	ARI
AVDEPTH	AVGDPTH	Average Depth:Average depth of the play	Feet	UGR Type; Play; Quality	ARI
BASINDIFF	BASNDIF	Basin Differential: This is a sensitivity on the gas price at a basin level. Depending on their proximity to market and infrastructure, the price varies throughout the country. The numbers are constant throughout the model.	1996$/ Mcf	UGR Type; Play; Quality	ARI
BNAREA	BASAR	Basin Area: Area in square miles	Square Miles	UGR Type; Play; Quality	ARI
CAPCSTDH	CCWDH	Capital Costs with Dry Hole Costs	1996$/ Mcf	UGR Type; Play; Quality	ARI
CTUNDRLOC	CTUL	Undrilled Locations - Current Technology: Current number of locations available to drill	-	UGR Type; Play; Quality	ARI
DCCOST	DACC	Drilling and completion costs	1996$	UGR Type; Play; Quality	ARI
DCCOSTGT	DCC_G2K	Drilling and completion cost per foot, well is greater than 2000 feet.	1996$/ Foot	UGR Type	ARI
DCCOSTLT	DCC_L2K	Cost per foot, well is less than 2000 feet.	1996$/ Foot	UGR Type	ARI

[1]The four AQuality@ Categories are Total, Best 30%, Next Best 30%, and Worst 40%.

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
DEVCELLS	DEV_CEL	Developed Cells: Number of locations already drilled	-	UGR Type; Play; Quality	ARI
DISCFAC	DIS_FAC	Discount Factor: This is the discount factor that is applied to the EUR for each well. The Present Value of a production stream from a typical coalbed methane, tight sands, or gas shales well is discounted at a rate of 15%.over a twenty year period.	Fraction	UGR Type	ARI
DISCRES	DISCRES	Discounted Reserves: The mean EUR per well multiplied by the discount factor.	Bcf	UGR Type; Play; Quality	Calculated
DRILLSCHED	DRL_SCHED	Drilling Schedule	Years	UGR Type; Play; Quality	ARI
DRILLSCHED	DRL_SCHED2	Drilling Schedule adjusted to account for technological progress	Years	UGR Type; Play; Quality	ARI
DRILLSCHED	DRL_SCHED3	Drilling Schedule: This variable ensures that adjustment for technology did not result in negative value for emerging basin Drilling Schedule.	Years	UGR Type; Play; Quality	ARI
DRILLSCHED	DRL_SCHED4	Drilling Schedule: This variable adjusts to account for the time-delaying effect of access limitations	Years	UGR Type; Play; Quality	ARI
DRRESADDS	DRA	Drilled Reserve Additions	Bcf	UGR Type; Play; Quality	Calculated
DRYHOLECOST	DHC	Dry Hole Costs	1996$/ Well	UGR Type; Play; Quality	Calculated
EMBASINYRS* FINFAC	EMERG#	The number of years taken off the drilling schedule for an advancement in technology.	Years	UGR Type; Play	ARI
EMERGBAS	EMRG	The parameter that determines if the play is an emerging basin. This designation was made by ARI (1=yes).	-	UGR Type; Play; Quality	ARI

Unconventional Gas Recovery Supply Submodule					
Variable Name					
Code	**Text**	**Brief Description**	**Unit**	**Classification**	**Source**
ENCBMYRCST	ECBM_OC	Enhanced CBM Operating Costs Variable - $1.00	1996$/ Mcf	UGR Type[CBM]; Basin; Quality	ARI
ENVIRONREG	ENV%	The percentage of the play that is not restricted from development due to environmental or pipeline regulations	Fraction	UGR Type; Play	ARI
ENVPIPREG	ENPRGS	Establishes if the play is pipeline or environmentally regulated (1=yes).	-	UGR Type; Play; Quality	ARI
EXNPVREV	ENPVR	Expected NPV Revenues: Gives the value of the entire discounted production stream for one well in real $.	1996$/ Well	UGR Type; Play; Quality	Calculated
FINFAC	TECHYRS	Number of years (from base year) over which incremental advances in indicated technology have occurred	Years	-	Calculated
FIXOMCOST	FOMC	Fixed Operating and Maintenance Costs	1996$/ Well	UGR Type; Play; Quality	Calculated
GA10	GAA10	Variable General and Administrative (G&A) Costs:	1996$/ Well	UGR Type; Play; Quality	Calculated
GABASE	RST	Variable G&A Costfactor - Currently 10% of equiprment costs, stimulation costs, and drilling costs	Fraction	UGR Type; Play; Quality	Calculated
H2OBASE	WOML_WTR	Water Producing Well Lease Equipment Costs	1996$/ Well	UGR Type; EUR Level	ARI
H2ODISP	WATR_DISP	Establishes if the play requires water disposal (1 = yes)	-	UGR Type; Play; Quality	ARI
HYPPLAYS	HYP%	Establishes whether or not the play is hypothetical (1=yes)	-	UGR Type; Play; Quality	ARI
			1996$/	UGR Type; EUR	

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
LANDGG	DCC_G&G	Land / G&G Costs	Well	level	ARI
LANDGGH2O	WOMM_OMW	Operating & Maintenance - Medium well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LANDGGH2O	WOMS_OMW	Operating & Maintenance - Small well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LANDGGH2O	WOML_OMW	Operating & Maintenance - Large well with H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
LEASSTIP	LEASSTIP	Lease Stipulated Share: The percentage of undrilled locations in a play that are subject to Federal lease stipulations	Percent	UGR Type; Play	ARI
LEASEQUIP	LSE_EQ	Lease Equipment Costs	$1996/ Well	UGR Type; Play; Quality	ARI
LSEQBASE	WOML_LE	Large Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
LSEQBASE	WOMS_LE	Small Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
LSEQBASE	WOMM_LE	Medium Well Lease Equipment Costs	$1996/ Well	UGR Type; EUR Level	ARI
MEANEUR	MEUR1	A weighted average of the EUR values for each (entire) basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR1	A weighted average of the EUR values for the best 30% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR1	A weighted average of the EUR values for the middle 30% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
MEANEUR	MEUR1	A weighted average of the EUR values for the worst 40% of the wells in the basin	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR2	For Coalbed Methane, ᴀMEUR1" adjusted for technological progress in the development of new cavity fairways	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR3	For Enhanced Coalbed Methane, ᴀMEUR2" adjusted for technological progress in the commercialization of Enhanced Coalbed Methane	Bcf/Well	UGR Type; Play; Quality	Calculated
MEANEUR	MEUR4	Mean EUR: This variable establishes whether or not the play is profitable and if so, allows the EUR to appear for development.	Bcf/Well	UGR Type; Play; Quality	Calculated
MIN_ROI	MIN_ROI	A risk premium - the minimum rate of return that a project must be expected to achieve to offset risk of investment	1996$/Mcf	UGR Type	ARI
NETPR	NET_PRC	Net Price ($/Mcf): Including Royalty and Severance Tax	1996$/Mcf	UGR Type; Play; Quality	Calculated
NETPROFIT	NET_PROF	Net Profits ($/Mcf)	1996$/Mcf	UGR Type; Play; Quality	Calculated
NETPROFIT	NET_PROF2	Net Profits (changed to 0 if < 0): Allows only the profitable plays to become developed	1996$/Mcf	UGR Type; Play; Quality	Calculated
NEWWELLS	NW_WELLS	New Wells: The amount of wells drilled for the play in that year	Wells	UGR Type; Play; Quality	Calculated
NEWWELLS_LAG	NW_WELLS_LAG	New Wells Lagged: The amount of wells drilled for the play in the previous year	Wells	UGR Type; Play; Quality	Calculated
NEWWELLS	NW_WELLS2	New Wells: This variable ensures the wells drilled is a positive value.	Wells	UGR Type; Play; Quality	Calculated
NOACCESS	NOACCESS	No Access Share: The percentage of undrilled locations in a	Percent	UGR Type;	ARI

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
		play that are legally inaccessible		Play	
NYR_UNDEVWELLS	UNDV_WELLS2	Undeveloped wells available to be drilled for the next year	Wells	UGR Type; Play; Quality	Calculated
1.32*OGPRCL48	WHGP	Wellhead Gas Price	1996$/Mcf	UGR Type; OGSM Region	NGTDM (Integrated); Input (Standalone)
OPCOSTH2O	OCWW$	Operating Costs with H2O - $0.30	1996$/Mcf	UGR Type; H2O Disposal Level	ARI
OPCOSTH2O	OCNW$	Operating Costs without H2O - $0.25	$1996/Mcf	UGR Type; H2O Disposal Level	ARI
OPCSTGASTRT	GASTR	Gas Treatment and Fuel costs - $0.25	$1996/Mcf	UGR Type	ARI
OPCSTH2ODISP	WTR_DSPT	Water Disposal Fee: $0.05	$1996/Mcf	UGR Type	ARI
OPCSTOMS	WOMS	H2O Costs, Small Well	$1996/Mcf	UGR Type	ARI
PLAYPROBBASE	PLPROB	The play probability: Only hypothetical plays have a PLPROB < 100%.	Fraction	UGR Type; Play; Quality	ARI
PLAYPROB	PLPROB2	The play probability adjusted for technological progress, if initial play probability less than 1.	Fraction	UGR Type; Play; Quality	Calculated
PMPSFEQBASE	BASET	Variable cost of Pumping and Surface equipment when H2O disposal is required.	1996$/Well	UGR Type; Play; Quality	ARI
PMPSURFEQ	PASE	Pumping and Surface Equipment Costs	1996$/Well	UGR Type; Play; Quality	Calculated

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
PROD	PROD	Current Production	Bcf	UGR Type; Play; Quality	Calculated
PROD	PROD2	Production for the next year	Bcf	UGR Type; Play; Quality	Calculated
PROVRESV	PROV_RES	Proved Reserves	Bcf	UGR Type; Play; Quality	Calculated
PROVRESV	PROV_RES2	Proved Reserves for the next year	Bcf	UGR Type; Play; Quality	Calculated
RESADDS	R_ADD	Total Reserve Additions	Bcf	UGR Type; Play; Quality	Calculated
RESGRADDS	RGA	Reserve Growth Additions	Bcf	UGR Type; Play; Quality	Calculated
RESGRWTH	RES_GR	Establishes whether or not the play will have reserve growth (1=yes)	-	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW101	Reserves per Well for the best 10% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW201	Reserves per Well for the next (lesser) 20% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW301	Reserves per Well for the next (lesser) 30% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCFB	RW401	Reserves per Well for the worst 40% of the play (year 1): an EUR estimate	Bcf/Well	UGR Type; Play; Quality	ARI
RESWELLBCF	RW101	Reserves per Well for the best 10% of the play (years 2,20)	Bcf/Well	UGR Type; Play;	Calculated

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
				Quality	
RESWELLBCF	RW201	Reserves per Well for the next (lesser) 20% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RESWELLBCF	RW301	Reserves per Well for the next (lesser) 30% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RESWELLBCF	RW401	Reserves per Well for the worst 40% of the play (years 2,20)	Bcf/Well	UGR Type; Play; Quality	Calculated
RES_GRTH_DEC	RGR	Reserve Growth Rate	Fraction	UGR Type; Year	ARI
ROYSEVTAX	RST	Variable Royalty and Severance Tax - Set at 17%	Fraction	UGR Type	ARI
RP	R/P_RAT	Reserves-to-Production (R/P) Ratio	Fraction	UGR Type; Play; Quality	Calculated
RP	RP_RAT2	R/P Ratio for the next year	Fraction	UGR Type; Play; Quality	Calculated
RSVPRD	RESNPROD	Reserves and Production	Bcf	UGR Type; Play; Quality	Calculated
STIMCOST	STIMC	Stimulation Costs: Provides the cost of stimulating a well in the specific basin by multiplying the given average stimulation cost by the number of stimulation zones.	1996$/Well	UGR Type; Play; Quality	ARI
STIMCSTBASE	STIM_CST	Variable average cost of stimulating one zone. (Number of zones is a variable)	1996$/Zone	UGR Type	ARI
STIMUL	SZONE	Stimulation Zones: Number of times a single well is stimulated in the play	-	UGR Type; Play; Quality	ARI
		Success Rate : The ratio of successful wells over total wells		UGR Type; Play;	

Unconventional Gas Recovery Supply Submodule					
Variable Name					
Code	**Text**	**Brief Description**	**Unit**	**Classification**	**Source**
SUCRATE	SCSSRT	drilled (This can also be called the dry hole rate if you use the equation 1 - SCSSRT).	Fraction	Quality	ARI
TECHRECWELL	TRW1	The amount of technically recoverable wells available regardless of economic feasibility.	Wells	UGR Type; Play; Quality	Calculated
TECH_PROG_ SCHED_DR	REDAM%	Total percentage increase over development period due to advances in ΑReduced Damage D&S@ technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_DR	FRCLEN%	Total percentage increase over development period due to advances in ΑIncreased Fracture Length L&C@ technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_DR	PAYCON%	Total percentage increase over development period due to advances in ΑImproved Pay Contact@ technology	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_EX	EMERG%	The number of years added onto the drilling schedule because of the hindrance of the play being an emerging basin.	Years	UGR Type	ARI
TECH_PROG_ SCHED_PT	WDT%	Total percentage decrease in H2O disposal and treatment costs over the development period due to technological advances	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	PUMP%	Total percentage decrease in pumping costs over the development period due to technological advances	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	GTF%	Total percentage decrease in gas treatment and fuel costs over the development period due to technological advances	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	LOW%	The percentage of the play that is restricted from development due to environmental or pipeline regulations	Fraction	UGR Type	ARI
TECH_PROG_ SCHED_PT	LOWYRS	The number of years the environmental and or pipeline regulation will last.	Years	UGR Type	ARI
TECH_PROG_ SCHED_PT	ENH_CBM%	Enhanced CBM EUR Percentage gain	Fraction	UGR Type[CBM]	ARI

Unconventional Gas Recovery Supply Submodule

Variable Name		Brief Description	Unit	Classification	Source
Code	Text				
TECH_PROG_ SCHED_EX	DEVPER	Development period for AFavorable Settings@ technological advances	Years	UGR Type	ARI
TOTCAPCOST	TCC	Total Capital Costs: The sum of Stimulation Costs, Pumping and Surface Equipment Costs, Lease Equipment Costs, G&A Costs and Drilling and Completion Costs	1996$/Well	UGR Type; Play; Quality	Calculated
TOTCOST	TOTL_CST	Total Costs ($/Mcf)	1996$/Mcf	UGR Type; Play; Quality	Calculated
ULTRECV	URR	Ultimate Recoverable Resources	Bcf	UGR Type; Play; Quality	Calculated
UNDEVRES	UNDEV_RES	Undeveloped resources	Bcf	UGR Type; Play; Quality	Calculated
UNDEV_WELLS	UNDV_WELLS	Undeveloped wells available for development under current economic conditions	Wells	UGR Type; Play; Quality	Calculated
VAROPCOST	VOC	Variable Operating Costs	1996$/Mcf	UGR Type; Play; Quality	Calculated
VAROPCOST	VOC2	Variable Operating Costs: Includes an extra operating cost for plays that will incorporate the technology of Enhanced CBM in the future	1996$/Mcf	UGR Type; Play; Quality	Calculated
WELLSP	WSPAC_CT	Well Spacing - Current Technology: Current spacing in acres	Acres	UGR Type; Play; Quality; Technology Level	ARI
WELLSP	WSPAC_AT	Well Spacing - Advanced Technology: Spacing in acres under Advanced Technology	Acres	UGR Type; Play; Quality; Technology Level	ARI

Unconventional Gas Recovery Supply Submodule					
Variable Name		**Brief Description**	**Unit**	**Classification**	**Source**
Code	**Text**				
.6*LANDGGH2O	WOMS_OM	Operating & Maintenance - Small well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
.6*LANDGGH2O	WOMM_OM	Operating & Maintenance - Medium well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI
.6*LANDGGH2O	WOML_OM	Operating & Maintenance - Large well without H2O disposal	$1996/ Well	UGR Type; EUR Level	ARI

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Appendix C. Model Abstract

1. Model Name
    Oil and Gas Supply Module

2. Acronym
    OGSM

3. Description
    OGSM projects the following aspects of the crude oil and natural gas supply industry:
    - production
    - reserves
    - drilling activity
    - natural gas imports and exports

4. Purpose
    OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
    2008

6. Part of Another Model
    National Energy Modeling System (NEMS)

7. Model Interface References
    Coal Module
    Electricity Module
    Industrial Module
    International Module
    Natural Gas Transportation and Distribution Model (NGTDM)
    Macroeconomic Module
    Petroleum Market Module (PMM)

8. Official Model Representative
    - Office: Integrating Analysis and Forecasting
    - Division: Oil and Gas Analysis
    - Model Contact: Dana Van Wagener
    - Telephone: (202) 586-4725

9. Documentation Reference
    U.S. Department of Energy. 2007. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2008

11. Energy Systems Described

The OGSM forecasts oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves and development determines the rate of production from the stock of known reserves.

The OGSM also projects natural gas trade via pipeline with Canada, Mexico, and the Bahamas. U.S. natural gas trade with Canada is represented by seven entry/exit points and trade with Mexico by three entry/exit points.

12. Coverage
   ! Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
   ! Time Units/Frequency: Annually 1990 through 2030
   ! Product(s): Crude oil and natural gas
   ! Economic Sector(s): Oil and gas field production activities and foreign natural gas trade

13. Model Features
   ! Model Structure: Modular, containing six major components
      - Lower 48 Onshore Supply Submodule
      - Unconventional Gas Recovery Supply Submodule
      - Offshore Oil and Gas Supply Submodule
      - Foreign Natural Gas Supply Submodule
      - Alaska Oil and Gas Supply Submodule
      - Oil Shale Supply Submodule
   ! Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are determined by the discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables. LNG imports are projected on the basis of unit supply costs for gas delivered into the Lower 48 pipeline network.
   ! Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
   ! Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
   ! Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
   ! Alaska Operating cost - U.S. Geological Survey
   ! Basin Differential Prices - Natural Gas Week, Washington, DC
   ! State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
   ! State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
   ! Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
   ! Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2005)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
   ! Shallow Offshore Drilling Costs - American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2005)*, Washington, D.C.
   ! Shallow Offshore Lease Equipment and Operating Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)

- ! Shallow Offshore Wells Drilled per Project - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- ! Shallow and Deep Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- ! Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
- ! Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook.*
- ! Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report,* Canada, April 2004.
- ! Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook.*
- ! Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- ! Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - ! Onshore Lease Equipment Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2003)*, DOE/EIA-0815(80-02)
    - ! Onshore Operating Cost - Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2005)*, DOE/EIA-0815(80-04)
    - ! Emissions Factors - Energy Information Administration
    - ! Oil and Gas Well Initial Flow Rates - Energy Information Administration, Office of Oil and Gas
    - ! Wells Drilled - Energy Information Administration, Office of Oil and Gas
    - ! Expected Recovery of Oil and Gas Per Well - Energy Information Administration, Office of Oil and Gas
    - ! Oil and Gas Reserves - Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2006), DOE/EIA-0216(77-07)

16. Computing Environment
    - ! Hardware Used: PC
    - ! Operating System: Windows 95/Windows NT/Windows XP
    - ! Language/Software Used: FORTRAN
    - ! Memory Requirement: Unknown
    - ! Storage Requirement: 992 bytes for input data storage; 180,864 bytes for output storage; 1280 bytes for code storage; and 5736 bytes for compiled code storage
    - ! Estimated Run Time: 9.8 seconds

17. Reviews conducted
    - ! Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - ! Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - ! Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts
        Not applicable

19. Bibliography
        See Appendix B of this document.

Appendix D. Parameter Estimation

The major portion of the lower 48 oil and gas supply component of the OGSM consists of a system of equations that are used to forecast exploratory and developmental wells drilled. The equations, the estimation techniques, and the statistical results are documented below. Documentation is also provided for the estimation of the drilling, lease equipment, and operating cost equations as well as the associated-dissolved gas equations and the Canada gas wells equation. Finally, the appendix documents the estimation of oil and gas supply price elasticities for possible use in short run supply functions. The econometric software package, TSP, was used for the estimations.

Onshore Lower 48 Total Wells Equations

The equations for total (successful plus dry) onshore oil wells and conventional natural gas wells were estimated using data for the onshore Lower 48 over the time period 1970 through 2004. The equations were estimated in log-linear form with correction for first order serial correlation using TSP version 4.5.

Total Onshore Oil Wells

$$\ln ESTWELLS_{k,t} = b0_k + b1_k * \ln POIL_t + \rho_k * \ln ESTWELLS_{k,t-1} - \rho_k * (b0_k + b1_k * \ln POIL_{t-1})\ \ (D-1)$$

for k = oil.

```
Dependent variable: LNTOTOILWELLS
Current sample:  1 to 35
Number of observations:  35
```

Mean of dep. var. = 9.80675	R-squared = .890509
Std. dev. of dep. var. = .669445	Adjusted R-squared = .883665
Sum of squared residuals = 1.69571	Durbin-Watson = 1.87815
Variance of residuals = .052991	Schwarz B.I.C. = -.260316
Std. error of regression = .230198	Log likelihood = 5.59334

Parameter	Estimate	Standard Error	t-statistic	P-value
$b0_k$	8.01558	.636090	12.6013	[.000]
$b1_k$	.535231	.137432	3.89452	[.000]
ρ_k	.950729	.046576	20.4125	[.000]

Total Onshore Conventional Natural Gas Wells

$$\ln ESTWELLS_{k,t} = b0_k + b1_k * \ln PGAS_t + \rho_k * \ln ESTWELLS_{k,t-1} - \rho_k * (b0_k + b1_k * \ln PGAS_{t-1})\ (D-2)$$

for k = gas.

```
Dependent variable: LNTOTGASWELLS
Current sample:  1 to 35
Number of observations:  35
```

Mean of dep. var. = 9.59757	R-squared = .878884
Std. dev. of dep. var. = .365107	Adjusted R-squared = .871314
Sum of squared residuals = .573567	Durbin-Watson = 1.72432
Variance of residuals = .017924	Schwarz B.I.C. = -16.4080
Std. error of regression = .133880	Log likelihood = 21.7411

Parameter	Estimate	Standard Error	t-statistic	P-value
$b0_k$	9.15143	.129261	70.7979	[.000]
$b1_k$	.594489	.098560	6.03176	[.000]
ρ_k	.823041	.087371	9.42002	[.000]

Onshore Lower 48 Available Rigs Equation

The equation for total available onshore rigs was estimated using data for the onshore Lower 48 over the time period 1970 through 2002. The equations were estimated in log-linear form with correction for first order serial correlation using TSP version 4.5.

$$\ln RIGSL48_t = b0 + b1 * \ln RIGSL48_{t-1} + b2 * \ln REVRIG_{t-1} + \rho * \ln RIGSL48_{t-1}$$
$$- \rho * (b0 + b1 * \ln RIGSL48_{t-2} + b2 * \ln REVRIG_{t-2})$$

(D-3)

```
Dependent variable: lnRIGSL48_t
Number of observations:  31

        Mean of dep. var. = 7.71468   Adjusted R-squared = .977595
   Std. dev. of dep. var. = .412360        Durbin-Watson = 1.69993
 Sum of squared residuals = .102867   Common Factor test = .01249[.911]
    Variance of residuals = .380991E-02   Schwarz B.I.C. = -37.6236
 Std. error of regression = .061724      Log likelihood = 44.4916
                R-squared = .979836


                            Standard
Parameter     Estimate       Error      t-statistic     P-value
   b0        -.575248       1.03514      -.555720        [.578]
   b1         .713897        .135602      5.26466        [.000]
   b2         .172923        .048995      3.52942        [.000]
    ρ         .929042        .131129      7.08496        [.000]
```

Onshore Lower 48 Drilling Cost Equations

The onshore Lower 48 per well drilling costs equations were estimated for onshore regions 1 through 6 for successful and dry oil wells and for successful and dry conventional natural gas wells using region-specific data for the 1970-2005 time period. The equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity using TSP version 4.5. An adjustment factor was also estimated to correct for the downward bias caused by the logarithmic transformation. Instruments included six regional dummy variables, lagged values of the dependent and independent variables, and constant values for the technology improvement factor (-0.5% per year) and the capital cost escalation factor (0.1560 per year).

$$\text{(D-4)}$$

$$\ln \text{DRILLCOST}_{r,k,t} = b0_{r,k} + b1_k * \ln ESTWELLS_t + b2_k * DEPTH_{r,k,t} + b3_k * TIME_t + CAPCOST +$$

$$\rho_k * (\ln DRILLCOST_{r,k,t-1} - (b0_{r,k} + b1_k * \ln ESTWELLS_{t-1} + b2_k * DEPTH_{r,k,t-1} + b3_k * TIME_{t-1} + CAPCOST))$$

$$\text{(D-5)}$$

$$\ln \text{DRYCOST}_{r,k,t} = c0_{r,k} + c1_k * \ln ESTWELLS_t + c2_k * DEPTH_{r,k,t} + c3_k * TIME_t + CAPCOST -$$

$$\rho_k * (\ln DRYCOST_{r,k,t-1} * (c0_{r,k} + c1_k * \ln ESTWELLS_t + c2_k * DEPTH_{r,k,t-1} + c3_k * TIME_{t-1} + CAPCOST))$$

for regions 1 through 6, O = oil, and G = shallow gas and deep gas combined, DO = dry oil hole, and DG = dry gas hole.

Parameter	Estimate	Standard Error	t-statistic	P-value
O1	18.3617	.370755	48.9856	[.000]
O2	18.8043	.339479	55.1404	[.000]
O3	18.5614	.336079	54.7315	[.000]
O4	18.6782	.337758	54.7393	[.000]
O5	19.0255	.338584	55.6421	[.000]
O6	19.4508	.422396	45.7225	[.000]
OWELL	.288062	.029307	9.58490	[.000]
ODPTH	.167991E-03	.848757E-05	21.9390	[.000]
ORHO	.905463	.011186	79.7301	[.000]
G1	17.8443	.317201	56.3118	[.000]
G2	18.3822	.292665	62.6188	[.000]
G3	18.2207	.291140	62.2130	[.000]
G4	18.2810	.292450	62.0950	[.000]
G5	18.4957	.291733	62.9111	[.000]
G6	18.7192	.358778	51.7206	[.000]
GWELL	.322246	.025815	11.8467	[.000]
GDPTH	.189671E-03	.763952E-05	27.4194	[.000]
GRHO	.896752	.011724	74.9967	[.000]
DO1	18.8095	.490199	37.7038	[.000]
DO2	18.9733	.376820	50.3383	[.000]
DO3	18.5816	.371943	49.6571	[.000]
DO4	18.7585	.372941	49.8391	[.000]
DO5	19.3991	.379028	50.7356	[.000]
DO6	19.6384	.618158	31.7615	[.000]
DODPTH	.109253E-03	.591898E-05	19.5819	[.000]
DORHO	.921229	.966295E-02	94.5708	[.000]
DG1	18.4517	.455917	40.1944	[.000]
DG2	18.8211	.344746	54.4679	[.000]
DG3	18.4925	.339543	54.0829	[.000]
DG4	18.6318	.340789	54.1657	[.000]
DG5	19.1784	.346606	54.6461	[.000]
DG6	19.2494	.586425	32.5788	[.000]
DGDPTH	.106906E-03	.748693E-05	16.0886	[.000]
DGRHO	.930897	.880089E-02	104.928	[.000]

```
Number of observations = 1023

 Equation: OIL
 Dependent variable: LNOILDCST

        Mean of dep. var. = 12.6667  Std. error of regression = .175159
   Std. dev. of dep. var. = 1.11377             R-squared = .975689
 Sum of squared residuals = 31.3862        Durbin-Watson = 2.24825
[<1.00]
    Variance of residuals = .030681

 Equation: GAS
 Dependent variable: LNGASDCST

        Mean of dep. var. = 12.7827  Std. error of regression = .160078
   Std. dev. of dep. var. = 1.13142             R-squared = .980103
 Sum of squared residuals = 26.2142        Durbin-Watson = 2.28386
[<1.00]
    Variance of residuals = .025625

 Equation: DRY HOLE-OIL
 Dependent variable: LNDRYODCST

        Mean of dep. var. = 12.2780  Std. error of regression = .266707
   Std. dev. of dep. var. = 1.24527             R-squared = .955278
 Sum of squared residuals = 72.7689        Durbin-Watson = 2.27339
[<1.00]
    Variance of residuals = .071133

 Equation: DRY HOLE-GAS
 Dependent variable: LNDRYGDCST

        Mean of dep. var. = 12.3940  Std. error of regression = .235304
   Std. dev. of dep. var. = 1.25345             R-squared = .965401
 Sum of squared residuals = 56.6416        Durbin-Watson = 2.29244
[<1.00]
    Variance of residuals = .055368
```

Onshore Lower 48 Lease Equipment Cost Equations

The onshore Lower 48 per well lease equipment cost equations were estimated for onshore regions 1 through 6 for successful oil wells, successful shallow natural gas wells, and successful deep natural gas wells using region-specific data for the 1970-2004 time period. The equations were estimated in log-linear form using TSP version 4.5. Oil and shallow gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. Deep gas equations were estimated by nonlinear two stage least squares also with corrections for first order serial correlation and heteroscedasticity. Time trends were included as proxies for technological change. Instruments included six regional dummy variables, lagged values of the dependent and independent variables (depth, time), the lagged values of total onshore successful wells drilled, and the contemporaneous and lagged values of real oil and natural gas wellhead prices.

Lease Equipment Cost Equations for Oil and Shallow Gas

$$
\begin{aligned}
\ln LEQC_{r,k,t} = {}& b0_{r,k} + b1_k * \ln DEPTH_{r,k,t} + b2_k * \ln ESTSUCWELLS_t + b3 * TIME_t \\
& + \rho_k * \ln LEQC_{r,k,t-1} - \rho_k * (b0_{r,k} + b1_k * \ln DEPTH_{r,k,t-1} \\
& + b2_k * \ln ESTSUCWELLS_{t-1} + b3 * TIME_{t-1})
\end{aligned}
$$
(D-6)

for regions 1 through 6, O = oil and SG = shallow gas.

```
                          Standard
 Parameter   Estimate       Error        t-statistic   P-value
 O1          17.0780       2.32566        7.20917       [.000]
 O2          16.9033       2.32890        7.12413       [.000]
 O3          16.9465       2.32837        7.14429       [.000]
 O4          17.1109       2.32919        7.21236       [.000]
 O5          17.1421       2.32315        7.24457       [.000]
 O6          17.5322       2.32365        7.41090       [.000]
 ODEPTH      .531561       .046828        11.3512       [.000]
 OWELL       .117695       .022798        5.16259       [.000]
 TECH        -.554329E-02  .116765E-02    -4.74746      [.000]
 ORHO        .779529       .035211        22.1387       [.000]
 SG1         18.8895       2.25497        8.23852       [.000]
 SG2         19.3046       2.25571        8.41985       [.000]
 SG3         19.1722       2.25452        8.36552       [.000]
 SG4         19.4485       2.25573        8.48354       [.000]
 SG5         19.7749       2.25042        8.64862       [.000]
 SG6         18.9554       2.25540        8.26616       [.000]
 SGDEPTH     .192673       .037809        5.09599       [.000]
 SGWELL      .071634       .017891        4.00403       [.000]
 SGRHO       .820406       .030984        26.4781       [.000]
Number of observations = 212
```

```
Equation: OEQ
Dependent variable: LNOILLEQ

        Mean of dep. var. = 11.3233
  Std. dev. of dep. var. = .254016
Sum of squared residuals = .816920
    Variance of residuals = .385340E-02
Std. error of regression = .062076
                R-squared = .939999
            Durbin-Watson = 2.00943 [<.935]


Equation: SGEQ
Dependent variable: LNSGLEQ

        Mean of dep. var. = 10.1765
  Std. dev. of dep. var. = .336515
Sum of squared residuals = .600569
    Variance of residuals = .283287E-02
Std. error of regression = .053225
                R-squared = .974866
            Durbin-Watson = 1.66121 [<.153]
```

Lease Equipment Cost Equation for Deep Gas

$$\ln LEQC_{r,k,t} = b0_{r,k} + b1_k * ESTSUCWELLS_t + b2_k * TIME_t + \rho_k * \ln LEQC_{t-1}$$

$$- \rho_k * (b0_{r,k} + b1_k * ESTSUCWELLS_{t-1} + b2_k * TIME_{t-1})$$

(D-7)

for regions 2 through 5 and DG = deep gas.

```
                          Standard
Parameter   Estimate       Error        t-statistic    P-value
DG2         21.6473        2.32308      9.19569        [.000]
DG3         21.7030        2.32311      9.20790        [.000]
DG4         21.6722        2.32348      9.19318        [.000]
DG5         21.7380        2.32137      9.22989        [.000]
DGWELL      .139680        .017964      7.77545        [.000]
TECH        -.00584252     .120439E-02  -4.85100        [.000]
DGRHO       .740906        .047534      15.5868        [.000]


Equation: DGEQ
Dependent variable: LNDGLEQ

        Mean of dep. var. = 10.7480
  Std. dev. of dep. var. = .113803
Sum of squared residuals = .245411
    Variance of residuals = .181786E-02
Std. error of regression = .042636
                R-squared = .865712
        Adjusted R-squared = .859743
            Durbin-Watson = 1.39476 [<.003]
```

Onshore Lower 48 Operating Cost Equations

The onshore Lower 48 per well operating cost equations were estimated for onshore regions 1 through 6 for successful oil wells, successful shallow natural gas wells, and successful deep natural gas wells using region-specific data for the 1970-2004 time period. The equations were estimated in log-linear form using TSP version 4.5. For regions 2 through 5, oil, shallow gas, and deep gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. For regions 1 and 6, oil and shallow gas equations were estimated simultaneously by Three Stage Least Squares with corrections for first order serial correlation and heteroscedasticity. A time trend was included to proxy for technological change in regions 2 through 5. Instruments included the six regional dummy variables, lagged values of the dependent and independent variables (depth, time), the lagged values of total onshore successful wells drilled (by fuel type), and the contemporaneous and lagged values of real oil and natural gas wellhead prices.

Operating Cost Equations for Regions 2 through 5

$$\ln OPC_{r,k,t} = b0_{r,k} + b1_k * \ln DEPTH_{r,k,t} + b2_k * \ln ESTSUCWELLS_{k,t} + b3 * TIME_t + b4 * PGAS_{r,t}$$
$$+ \rho_k * \ln OPC_{r,k,t-1} - \rho_k * (b0_{r,k} + b1_k * \ln DEPTH_{r,k,t-1} + b2_k * \ln ESTSUCWELLS_{k,t-1} \qquad (D8)$$
$$+ b3 * TIME_{t-1} + b4 * PGAS_{r,t-1})$$

for regions 2 through 5 and O = oil, SG = shallow gas, DG = deep gas

```
                         Standard
Parameter   Estimate       Error       t-statistic    P-value
O2          12.3324      3.78769        3.25592        [.001]
O3          12.0899      3.78664        3.19277        [.001]
O4          12.0249      3.78816        3.17434        [.002]
O5          12.2276      3.79039        3.22596        [.001]
ODEPTH      .511000      .061549        8.30240        [.000]
OWELL       .061157      .029055        2.10490        [.035]
OPGAS       .098755      .014765        6.68843        [.000]
TECH        -.387879E-02  .186574E-02  -2.07896        [.038]
ORHO        .869890      .035798        24.3001        [.000]
SG2         15.0049      3.70056        4.05476        [.000]
SG3         14.8681      3.69924        4.01922        [.000]
SG4         14.9550      3.69842        4.04360        [.000]
SG5         15.2000      3.69926        4.10894        [.000]
SGDEPTH     .170114      .022831        7.45094        [.000]
SGWELL      .104588      .020382        5.13135        [.000]
SGRHO       .858446      .028669        29.9433        [.000]
DG2         14.1964      3.76649        3.76914        [.000]
DG3         14.2069      3.77105        3.76735        [.000]
DG4         14.1406      3.76751        3.75330        [.000]
DG5         14.3170      3.76865        3.79898        [.000]
DGDEPTH     .310969      .057660        5.39319        [.000]
DGWELL      .084408      .016458        5.12869        [.000]
DGRHO       .831782      .030235        27.5101        [.000]

Standard Errors computed from quadratic form of analytic first derivatives
(Gauss)

Equation: Oil
```

```
Dependent variable: LNOILOPR

        Mean of dep. var. = 9.55231
   Std. dev. of dep. var. = .321116
 Sum of squared residuals = .539383
     Variance of residuals = .385273E-02
Std. error of regression = .062070
                R-squared = .962390
            Durbin-Watson = 2.01036 [<.991]


Equation: Shallow Gas
Dependent variable: LNSGOPR

        Mean of dep. var. = 9.64790
   Std. dev. of dep. var. = .163563
 Sum of squared residuals = .211922
     Variance of residuals = .151373E-02
Std. error of regression = .038907
                R-squared = .943046
            Durbin-Watson = 1.84238 [<.917]


Equation: Deep Gas
Dependent variable: LNDGOPR

        Mean of dep. var. = 9.98982
   Std. dev. of dep. var. = .111304
 Sum of squared residuals = .149442
     Variance of residuals = .106744E-02
Std. error of regression = .032672
                R-squared = .914042
            Durbin-Watson = 1.55276 [<.372]
```

Operating Cost Equations for Region 1 and Region 6

$$\ln OPC_{r,k,t} = b0_{r,k} + b1_k * DEPTH_{r,k,t} + b2_k * ESTSUCWELLS_t + b3 * PGAS_{r,t} + \rho_k * \ln OPC_{r,k,t-1}$$

$$- \rho_k * (b0_{r,k} + b1_k * DEPTH_{r,k,t-1} + b2_k * ESTSUCWELLS_{t-1} + b3 * PGAS_{r,t-1})$$

(D-9)

for regions 1 and 6, O = oil and SG = shallow gas.

```
                          Standard
Parameter   Estimate        Error       t-statistic   P-value
O1          7.05992        .487893       14.4702       [.000]
O6          7.16017        .469441       15.2525       [.000]
ODEPTH      .230508        .046930       4.91178       [.000]
OWELL       .046722        .023593       1.98032       [.048]
OPGAS       .038815        .894386E-02   4.33979       [.000]
ORHO        .808952        .040443       20.0020       [.000]
SG1         6.32913        .368423       17.1789       [.000]
SG6         6.33875        .387009       16.3788       [.000]
SGDEPTH     .252312        .042043       6.00125       [.000]
SGWELL      .078949        .019726       4.00219       [.000]
SGRHO       .817840        .034096       23.9866       [.000]


Standard Errors computed from quadratic form of analytic first derivatives
(Gauss)


Equation: Oil
Dependent variable: LNOILOPR
```

```
        Mean of dep. var. = 9.36313
  Std. dev. of dep. var. = .144585
Sum of squared residuals = .089443
   Variance of residuals = .127776E-02
Std. error of regression = .035746
              R-squared = .938139
          Durbin-Watson = 1.82622 [<.896]


Equation: Shallow Gas
Dependent variable: LNSGOPR

        Mean of dep. var. = 9.16025
  Std. dev. of dep. var. = .129223
Sum of squared residuals = .037224
   Variance of residuals = .531775E-03
Std. error of regression = .023060
              R-squared = .967983
          Durbin-Watson = 1.61016 [<.638]
```

Return on Investment Equations

The return on domestic and foreign (drilling) investment (ROI) equations were estimated in log form over the sample period 1981-2003 for the domestic ROI and 1978-2003 for the foreign ROI. The natural log of the world oil price in US$1997 served as the explanatory variable for both equations. The equations were estimated with least squares using TSP version 5.0.

Return on Investment, U.S.

$$\ln\text{ROI\_US}_t = \alpha0 + \alpha1 * \ln\text{POIL97}_t \tag{D-10}$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: lnROI_US
 Number of observations:  23

        Mean of dep. var. = -2.18587      LM het. test = 4.31949 [.038]
  Std. dev. of dep. var. = .499339       Durbin-Watson = 2.13573 [<.678]
Sum of squared residuals = 1.42871    Jarque-Bera test = 30.8425 [.000]
   Variance of residuals = .068034     Ramsey's RESET2 = 16.0370 [.001]
Std. error of regression = .260833     F (zero slopes) = 59.6285 [.000]
              R-squared = .739546       Schwarz B.I.C. = 3.81577
     Adjusted R-squared = .727144       Log likelihood = -.680279

                         Standard
Parameter    Estimate      Error      t-statistic    P-value
α0          -5.51544      .434599       -12.6909      [.000]
α1           1.08797      .140894        7.72195      [.000]
```

Return on Investment, Foreign

$$lnROI\_FOREIGN_t = \alpha0 + \alpha1 * lnPOIL97_t \qquad\qquad (D-11)$$

```
Method of estimation = Ordinary Least Squares

 Dependent variable: lnROI_FOREIGN
 Number of observations:  26

        Mean of dep. var. = -2.10756      LM het. test = 4.15958 [.041]
   Std. dev. of dep. var. = .520279       Durbin-Watson = 2.09367 [<.643]
 Sum of squared residuals = 1.66202   Jarque-Bera test = 29.8888 [.000]
    Variance of residuals = .069251     Ramsey's RESET2 = 24.6236 [.000]
 Std. error of regression = .263155     F (zero slopes) = 73.7210 [.000]
               R-squared = .754403       Schwarz B.I.C. = 4.39967
      Adjusted R-squared = .744170       Log likelihood = -1.14157

                      Standard
Parameter   Estimate   Error       t-statistic   P-value
α0          -5.51668   .400391      -13.7782       [.000]
α1           1.05394   .122750        8.58609      [.000]
```

U.S. Exploration and Development Budget Equation

The U.S. exploration and development budget equation was estimated using data over the 1981-2003 time period. Explanatory variables included the return on foreign drilling investment, the ratio of price to operating cost for both oil and natural gas, and the lagged value of natural gas production. The equation was estimated using least squares with TSP version 4.5.

$$lnUS\_ED\_97_t = \beta0 + \beta1 * lnROI\_FOREIGN_t + \beta2 * lnPCRATIO\_GAS_t$$
$$+ \beta3 * lnPCRATIO\_OIL_t + \beta4 * lnGAS\_PROD_{t-1} \qquad (D-12)$$

for t = 1981 to 2003.

```
Dependent variable: LN_ED_OGJ_97
Number of observations:  22

        Mean of dep. var. = 9.99804       LM het. test = .323036 [.570]
   Std. dev. of dep. var. = .490090       Durbin-Watson = 2.10409 [<.849]
 Sum of squared residuals = .681234   Jarque-Bera test = .628891 [.730]
    Variance of residuals = .040073     Ramsey's RESET2 = .123819 [.730]
 Std. error of regression = .200181     F (zero slopes) = 27.2176 [.000]
               R-squared = .864941       Schwarz B.I.C. = .720445
      Adjusted R-squared = .833162       Log likelihood = 7.00716

                         Standard
Parameter       Estimate    Error       t-statistic   P-value
β0              -62.8289    15.9899      -3.92928       [.001]
β1               -.273901    .076222     -3.59344       [.002]
β2              1.38388      .246907      5.60488       [.000]
β3              1.05841      .247702      4.27292       [.001]
β4              4.30038      .948648      4.53317       [.000]
```

Onshore Lower 48 Regional Wells Equations

Lower 48 onshore wells equations were estimated for each fuel type (oil, shallow gas, deep gas) by well type [exploratory (i = 1) disaggregated into new field wildcat wells and other exploratory wells, developmental (i = 2)] using panel data, i.e., data across regions over time. For oil and shallow gas, equations were estimated using data for the six onshore regions over the 1978-2004 time period; for deep gas, equations were estimated using data for regions 2 through 5 over the same time frame. All equations were estimated with corrections for heteroscedasticity and first-order serial correlation when necessary using TSP version 4.5. All equations assumed that the total number of wells drilled by fuel and well types is a function of the fuel- and well-specific regional discounted cash flow, the total industry exploration and development budget, and, in some instances, a measure of the remaining reserves (undiscovered or inferred) in the region.

<u>Onshore Oil New Field Wildcat Wells</u>

(D-13)

$$
\ln WELLSON_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_t + m2_{i,k} * \ln R\_UND_{r,k,t}
$$

$$
+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1}
$$

$$
+ m2_{i,k} * \ln R\_UND_{r,k,t-1})
$$

for i = 1 (exploratory), r = 1 through 6, and k = 1 (oil).

```
Dependent variable: lnWELLSON_{i,r,1,t}
Number of observations:  138

        Mean of dep. var. = 7.58272              R-squared = .969532
   Std. dev. of dep. var. = 3.94466     Adjusted R-squared = .967642
 Sum of squared residuals = 65.0807         Durbin-Watson = 2.13352
    Variance of residuals = .504502          Schwarz B.I.C. = 164.614
 Std. error of regression = .710283         Log likelihood = -142.441


                            Standard
Parameter     Estimate        Error       t-statistic    P-value
m00_{1,1,1}   -49.5721       11.4943       -4.31275       [.000]
m00_{1,2,1}   -58.0470       13.4256       -4.32361       [.000]
m00_{1,3,1}   -46.9802       11.1877       -4.19927       [.000]
m00_{1,4,1}   -55.3789       12.8914       -4.29581       [.000]
m00_{1,5,1}   -59.0009       13.6578       -4.31995       [.000]
m00_{1,6,1}   -57.1712       12.5756       -4.54620       [.000]
m1_{1,1}      .167250E-11    .893914E-12    1.87099       [.061]
m2_{1,1}      7.36887        1.57142        4.68930       [.000]
ρ_{1,1}       .757717        .056205       13.4814        [.000]
```

Onshore Oil Other Exploratory Wells

(D-14)

$$\ln\text{WELLSON}_{1,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * \text{DCFON}_{i,k,t-1} * \text{US\_ED\_97}_t + m2_{i,k} * \ln\text{R\_INFR}_{r,k,t}$$

$$+ \rho_{i,k} * \ln\text{WELLSON}_{1,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * \text{DCFON}_{i,k,t-2} * \text{US\_ED\_97}_{t-1}$$

$$+ m2_{i,k} * \ln\text{R\_INFR}_{r,k,t-1})$$

for i = 1 (exploratory), r = 1 through 6, and k = 1 (oil).

```
Dependent variable: lnWELLSON_{i,r,1,t}
Number of observations:  138

        Mean of dep. var. = 9.61137          Adjusted R-squared = .975461
  Std. dev. of dep. var. = 5.36141                Durbin-Watson = 1.94553
 Sum of squared residuals = 91.0803      Variance of residuals = .706049
            Schwarz B.I.C. = 188.547    Std. error of regression = .840267
            Log likelihood = -166.374
                 R-squared = .976894

                          Standard
Parameter     Estimate      Error        t-statistic    P-value
m00_{1,1,1}   -41.0268     4.50037       -9.11630       [.000]
m00_{1,2,1}   -48.0967     5.12674       -9.38154       [.000]
m00_{1,3,1}   -45.4062     4.99955       -9.08207       [.000]
m00_{1,4,1}   -52.6131     5.70673       -9.21948       [.000]
m00_{1,5,1}   -52.4093     5.57675       -9.39782       [.000]
m00_{1,6,1}   -53.0492     5.42059       -9.78661       [.000]
m1_{1,1}      .386517E-11  .133331E-11    2.89893       [.004]
m2_{1,1}      5.85551      .574367       10.1947        [.000]
ρ_{1,1}       .635415      .072186        8.80253       [.000]
```

Onshore Oil Development Wells

(D-15)

$$\ln\text{WELLSON}_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * \text{REG}r + m1_{i,k} * \text{DCFON}_{i,k,t-1} * \text{US\_ED\_97} + m2_{i,k} * \ln\text{R\_INFR}_{r,k,t}$$

$$+ \rho_{i,k} * \ln\text{WELLSON}_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * \text{REG}r + m1_{i,k} * \text{DCFON}_{i,k,t-2} * \text{US\_ED\_97}_{t-1}$$

$$+ m2_{i,k} * \ln\text{R\_INFR}_{r,k,t-1})$$

for i = 2 (development), r = 1 through 6, and k = 1 (oil).

```
Dependent variable: lnWELLSON₂,ᵣ,₁,ₜ
Number of observations:  138

        Mean of dep. var. = 22.1980        Adjusted R-squared = .989621
  Std. dev. of dep. var. = 8.32152              Durbin-Watson = 1.75490
 Sum of squared residuals = 92.7451     Variance of residuals = .718955
          Schwarz B.I.C. = 188.768    Std. error of regression = .847912
          Log likelihood = -166.595
               R-squared = .990227

                          Standard
Parameter   Estimate        Error       t-statistic   P-value
m00₂,₁,₁    -18.5658       2.48063       -7.48433      [.000]
m00₂,₂,₁    -22.4208       2.81319       -7.96989      [.000]
m00₂,₃,₁    -21.2510       2.75362       -7.71747      [.000]
m00₂,₄,₁    -24.9851       3.14393       -7.94709      [.000]
m00₂,₅,₁    -26.1016       3.07240       -8.49550      [.000]
m00₂,₆,₁    -24.4008       2.97725       -8.19574      [.000]
m1₂,₁       .132717E-10    .403664E-11   3.28781       [.001]
m2₂,₁       3.33851        .316625       10.5440       [.000]
ρ₂,₁        .626155        .069802       8.97047       [.000]
```

Onshore Shallow Gas New Field Wildcat Wells

$$(D-16)$$

$$\ln WELLSON_{i,r,k,t} = \sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_{t} + m2_{i,k} * \ln R\_UND_{r,k,t}$$

$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (\sum_{r=1}^{6} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1}$$

$$+ m2_{i,k} * \ln R\_UND_{r,k,t-1})$$

for i = 1 (exploratory), r = 1 through 6, and k = 2 (shallow gas).

```
Dependent variable: lnWELLSON_{i,r,2,t}
Number of observations:  144

        Mean of dep. var. = 14.8204          R-squared = .987561
   Std. dev. of dep. var. = 8.33048  Adjusted R-squared = .986824
 Sum of squared residuals = 123.457     Durbin-Watson = 2.02716
     Variance of residuals = .914494      Schwarz B.I.C. = 214.111
 Std. error of regression = .956292     Log likelihood = -191.746

                          Standard
Parameter    Estimate       Error        t-statistic    P-value
m00_{1,1,2}   -21.3258      2.79119       -7.64040       [.000]
m00_{1,2,2}   -27.8703      3.50129       -7.96002       [.000]
m00_{1,3,2}   -24.1065      3.03836       -7.93403       [.000]
m00_{1,4,2}   -24.1688      2.96456       -8.15257       [.000]
m00_{1,5,2}   -24.2727      3.07493       -7.89375       [.000]
m00_{1,6,2}   -22.7269      2.73188       -8.31915       [.000]
m1_{1,2}      .149913E-11   .432376E-12    3.46719       [.001]
m2_{1,2}      2.98012       .310706        9.59146       [.000]
ρ_{1,2}       .437027       .083378        5.24155       [.000]
```

Onshore Shallow Gas Other Exploratory Wells

$$(D-17)$$

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_t + m2_{i,k} * \ln R\_INFR_{r,k,t}$$
$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1}$$
$$+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})$$

for i = 1 (exploratory), r = 1 through 6, and k = 2 (shallow gas).

```
Dependent variable: lnWELLSON_{i,r,2,t}
Number of observations:  144

        Mean of dep. var. = 6.47025              R-squared = .868105
  Std. dev. of dep. var. = 1.64278  Adjusted R-squared = .865279
 Sum of squared residuals = 52.1358       Durbin-Watson = 1.72622
    Variance of residuals = .372398       Schwarz B.I.C. = 131.757
 Std. error of regression = .610245      Log likelihood = -121.818

                          Standard
Parameter     Estimate      Error       t-statistic   P-value
m0_{1,2}      1.28801      .917617       1.40365       [.160]
m1_{1,2}      .203825E-11  .703454E-12   2.89749       [.004]
m2_{1,2}      .337519      .093692       3.60245       [.000]
ρ_{1,2}       .849272      .044025       19.2907       [.000]
```

Onshore Shallow Gas Development Wells

$$(\text{D-18})$$

$$\ln\text{WELLSON}_{r,k,t} = m0_{i,k} + m00_{i,1,k} * REG1 + m1_{i,k} * \text{DCFON}_{i,k,t} * \text{US\_ED\_97}_t + m2_{i,k} * \ln R\_INFR_{r,k,t}$$
$$+ \rho_{i,k} * \ln\text{WELLSON}_{r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m00_{i,1,k} * REG1 + m1_{i,k} * \text{DCFON}_{i,k,t-1} * \text{US\_ED\_97}_{t-1}$$
$$+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})$$

for $i = 2$ (development), $r = 1$ through 6, $k = 2$ (shallow gas).

```
Dependent variable: lnWELLSON₂,ᵣ,₂,ₜ
Number of observations:  144

        Mean of dep. var. = 8.37035            R-squared = .873760
   Std. dev. of dep. var. = 2.01971  Adjusted R-squared = .870128
 Sum of squared residuals = 73.6582      Durbin-Watson = 1.85336
    Variance of residuals = .529915      Schwarz B.I.C. = 164.870
 Std. error of regression = .727953      Log likelihood = -152.445


                          Standard
Parameter     Estimate      Error      t-statistic   P-value
m0₂,₂         -.267052     .774845      -.344652      [.730]
m00₂,₁,₂       2.01636     .352430       5.72132      [.000]
m1₂,₂         .853375E-11  .437249E-11   1.95169      [.051]
m2₂,₂         .624420      .080524       7.75446      [.000]
ρ₂,₂          .738369      .056592      13.0473       [.000]
```

Onshore Deep Gas New Field Wildcat Wells

$$(D-19)$$

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_t + m2_{i,k} * \ln R\_UND_{r,k,t}$$
$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1}$$
$$+ m2_{i,k} * \ln R\_UND_{r,k,t-1})$$

for i = 1 (exploratory), r = 2 through 5, k = 3 (deep gas).

```
Dependent variable: lnWELLSON_{i,r,3,t}
Number of observations:  92

        Mean of dep. var. = 7.81332              R-squared = .983906
   Std. dev. of dep. var. = 6.31265     Adjusted R-squared = .983357
 Sum of squared residuals = 58.4306          Durbin-Watson = 1.81765
     Variance of residuals = .663984         Schwarz B.I.C. = 118.541
 Std. error of regression = .814852          Log likelihood = -109.497

                          Standard
Parameter    Estimate       Error       t-statistic    P-value
m0_{1,3}     -9.97155      1.40463       -7.09905       [.000]
m1_{1,3}     .192832E-12   .446271E-13    4.32097       [.000]
m2_{1,3}     1.31657       .131067       10.0450        [.000]
ρ_{1,3}      .647877       .083612        7.74860       [.000]
```

Onshore Deep Gas Other Exploratory Wells

$$\ln WELLSON_{i,r,k,t} = m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_t + m2_{i,k} * \ln R\_INFR_{r,k,t}$$
$$+ \rho_{i,k} * \ln WELLSON_{i,r,k,t-1} - \rho_{i,k} * (m0_{i,k} + m1_{i,k} * DCFON_{i,k,t-2} * US\_ED\_97_{t-1}$$
$$+ m2_{i,k} * \ln R\_INFR_{r,k,t-1})$$

for i = 1 (exploratory), r = 2 through 5, k = 3 (deep gas).

```
Dependent variable: lnWELLSON_i,r,3,t
Number of observations:  92
```

```
        Mean of dep. var. = 4.31008              R-squared = .834111
  Std. dev. of dep. var. = 1.90581    Adjusted R-squared = .828456
 Sum of squared residuals = 55.0352          Durbin-Watson = 2.00926
    Variance of residuals = .625399         Schwarz B.I.C. = 116.769
 Std. error of regression = .790822         Log likelihood = -107.726
```

```
                          Standard
Parameter    Estimate       Error       t-statistic   P-value
m0_1,3       -7.26067      1.99662       -3.63648      [.000]
m1_1,3       .203000E-12   .642782E-13   3.15815       [.002]
m2_1,3       .987747       .186312       5.30156       [.000]
ρ_1,3        .616164       .080327       7.67069       [.000]
```

Onshore Deep Gas Development Wells

(D-21)

$$\ln WELLSON_{i,r,k,t} = \sum_{r=2}^{5} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t} * US\_ED\_97_t + \rho_{i,k} * \ln WELLSON_{i,r,k,t-1}$$

$$- \rho_{i,k} * (\sum_{r=2}^{5} m00_{i,r,k} * REGr + m1_{i,k} * DCFON_{i,k,t-1} * US\_ED\_97_{t-1})$$

for i = 2 (development), r = 2 through 5, k = 3 (deep gas).

```
Dependent variable: lnWELLSON₂,ᵣ,₃,ₜ
Number of observations:  96

        Mean of dep. var. = 13.1999           R-squared = .990391
  Std. dev. of dep. var. = 6.87172  Adjusted R-squared = .989857
 Sum of squared residuals = 43.1191       Durbin-Watson = 1.86283
    Variance of residuals = .479101       Schwarz B.I.C. = 111.356
 Std. error of regression = .692171       Log likelihood = -97.6627

                           Standard
Parameter   Estimate        Error       t-statistic   P-value
m00₂,₂,₃    6.69258        .173802       38.5069       [.000]
m00₂,₃,₃    6.03841        .195721       30.8521       [.000]
m00₂,₄,₃    4.52244        .333805       13.5482       [.000]
m00₂,₅,₃    4.57595        .411420       11.1223       [.000]
m1₂,₃       .807514E-12    .242944E-12   3.32387       [.001]
ρ₂,₃        .778655        .065617       11.8667       [.000]
```

Onshore Lower 48 Conventional Finding Rates

New Field Wildcat Finding Rate (FR1): Oil

Oil discoveries per successful new field wildcat oil well were assumed to be a function of beginning of year remaining undiscovered oil reserves, the level of contemporaneous new field wildcat oil wells drilled, and the real average wellhead price of oil. The equation was estimated in log-linear form using OLS with correction for cross sectional heteroscedasticity using TSP version 4.5. The intercept was allowed to vary across regions. A dummy variable was included for those few observations for which conventional oil discoveries were estimated.

(D-22)

$$\ln FR1_{r,k,t} = \beta 0_k + \sum_{r=2}^{5} \beta 00_{r,k} * REGr + \beta 1_k * \ln RESOURCE_{r,k,t} + \beta 2_k * \ln SW1_{r,k,t} + \beta 3_k DUM_{r,k,t}$$

for r = 1 through 5 and k = 1 (oil).

```
Dependent variable: lnFR1r,1,t
Number of observations:  135

        Mean of dep. var. = -3.31654      LM het. test = .414327 [.520]
   Std. dev. of dep. var. = 2.04718        Durbin-Watson = 1.87111 [<.477]
 Sum of squared residuals = 133.389   Jarque-Bera test = 44.6543 [.000]
     Variance of residuals = 1.05031    Ramsey's RESET2 = .228119 [.634]
  Std. error of regression = 1.02485    F (zero slopes) = 58.2409 [.000]
                R-squared = .762478     Schwarz B.I.C. = 210.368
       Adjusted R-squared = .749386     Log likelihood = -190.746

                            Standard
Parameter     Estimate       Error        t-statistic    P-value
β0₁          -48.4099       5.97457        -8.10265       [.000]
β00₂,₁        -6.21458      1.05862        -5.87047       [.000]
β00₃,₁         1.09617       .396569        2.76413       [.007]
β00₄,₁        -4.24787       .782054       -5.43168       [.000]
β00₅,₁        -7.75580      1.19954        -6.46564       [.000]
β1₁           6.20903       .845037        7.34765       [.000]
β2₁           -.251571       .136088       -1.84859       [.067]
β3₁           -6.48964       .485741      -13.3603        [.000]
```

New Field Wildcat Finding Rate (FR1): Conventional Natural Gas (Shallow plus Deep)

Conventional natural gas discoveries per successful new field wildcat gas well were assumed to be a function of beginning of year remaining undiscovered gas reserves, the level of contemporaneous new field wildcat gas wells drilled, and the average depth of a new field wildcat gas well. The equation was estimated in log-linear form using OLS with correction for cross sectional heteroscedasticity using TSP version 4.5. The intercept was allowed to vary across regions. A dummy variable was included for those few observations for which conventional natural gas discoveries were estimated.

$$(D-23)$$

$$\ln FR1_{r,k,t} = \beta 0_k + \sum_{r=2}^{5} \beta 00_{r,k} * REGr + \beta 1_k * \ln RESOURCE_{r,k,t} + \beta 2_k * \ln SW1_{r,k,t} + \beta 3_k * \ln DEPTH_{r,k,t}$$
$$+ \beta 4_k DUM_{r,k,t}$$

for r = 1 through 6 and k = 2 & 3 (shallow gas and deep gas combined).

```
Dependent variable: lnFR1_{r,2&3,t}
Number of observations:  156

          Mean of dep. var. = .062788      LM het. test = .014487 [.904]
    Std. dev. of dep. var. = 1.34369      Durbin-Watson = 1.87873 [<.497]
 Sum of squared residuals = 117.797  Jarque-Bera test = .741855 [.690]
     Variance of residuals = .801339   Ramsey's RESET2 = 1.58927 [.209]
 Std. error of regression = .895175   F (zero slopes) = 25.2789 [.000]
                 R-squared = .579075    Schwarz B.I.C. = 222.169
        Adjusted R-squared = .556168   Log likelihood = -199.445
```

Parameter	Estimate	Standard Error	t-statistic	P-value
$\beta 0_{2\&3}$	-42.1606	5.06971	-8.31618	[.000]
$\beta 00_{2,2\&3}$	-6.97907	1.06511	-6.55243	[.000]
$\beta 00_{3,2\&3}$	-2.86506	.460140	-6.22648	[.000]
$\beta 00_{4,2\&3}$	-1.74551	.365197	-4.77965	[.000]
$\beta 00_{5,2\&3}$	-3.50929	.481650	-7.28598	[.000]
$\beta 1_{2\&3}$	3.72825	.439988	8.47353	[.000]
$\beta 2_{2\&3}$	-.412044	.091341	-4.51108	[.000]
$\beta 3_{2\&3}$	1.16490	.327734	3.55440	[.001]
$\beta 4_{2\&3}$	-1.96640	.388600	-5.06022	[.000]

Other Exploratory Finding Rate (FR2): Oil

The other exploratory finding rate for oil was assumed to be a function of beginning of year remaining inferred oil reserves and the level of contemporaneous other exploratory oil wells drilled. The equation was estimated in log-linear form with correction for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

$$(D-24)$$

$$\ln FR2_{r,k,t} = \beta 0_k + \beta 1_k * \ln INFR_{r,k,t} + \beta 2_k * \ln SW2_{r,k,t} + \rho_k * \ln FR2_{r,k,t-1}$$
$$- \rho_k * (\beta 0_k + \beta 1_k * \ln INFR_{r,k,t-1} + \beta 2_k * \ln SW2_{r,k,t-1})$$

for r = 1 to 6, k = 1 (oil).

```
Dependent variable: lnFR2_r,1,t
Number of observations = 156

        Mean of dep. var. = -.339276              R-squared = .862872
   Std. dev. of dep. var. = 2.07949     Adjusted R-squared = .860165
 Sum of squared residuals = 92.3697           LM het. test = 1.23033 [.267]
     Variance of residuals = .607695          Durbin-Watson = 2.26826 [<.973]
 Std. error of regression = .779548

                          Standard
Parameter   Estimate        Error        t-statistic    P-value
β0₁         -3.31186       1.18521        -2.79433       [.005]
β1₁          .711852        .131742        5.40336       [.000]
β2₁         -.787856        .061746      -12.7596        [.000]
ρ₁           .646368        .066212        9.76212       [.000]
```

Other Exploratory Finding Rate (FR2): Conventional Natural Gas (Shallow plus Deep)

The other exploratory finding rate for conventional natural gas was assumed to be a function of beginning of year remaining natural gas inferred reserves, the number of contemporaneous other exploratory gas wells drilled, the real wellhead price of natural gas, and the average depth of other exploratory wells drilled. The equation was estimated with corrections for heteroscedasticity and first order serial correlation using TSP version 4.5.

$$(D-25)$$

$$\ln FR2_{r,k,t} = \beta 0_k + \beta 1_k * \ln INFR_{r,k,t} + \beta 2_k * \ln SW2_{r,k,t} + \beta 3_k * \ln WHP_{r,k,t} + \rho_k * \ln FR2_{r,k,t-1}$$
$$- \rho_k * (\beta 0_k + \beta 1_k * \ln INFR_{r,k,t-1} + \beta 2_k * \ln SW2_{r,k,t-1} + \beta 3_k * \ln WHP_{r,k,t-1})$$

for r = 1 through 6 and k = 2 & 3 (shallow and deep gas combined).

```
Dependent variable: lnFR2_{r,2&3,t}
Number of observations = 150
```

Parameter	Estimate	Standard Error	t-statistic	P-value
$\beta 0_{2\&3}$	-3.58149	.610333	-5.86810	[.000]
$\beta 1_{2\&3}$	.878160	.061767	14.2172	[.000]
$\beta 2_{2\&3}$	-.942982	.069517	-13.5647	[.000]
$\beta 3_{2\&3}$	1.01654	.155763	6.52618	[.000]
$\rho_{2\&3}$	.566078	.070594	8.01876	[.000]

Onshore Lower 48 Oil Production to Reserves (PR) Ratio Equation

The oil production to reserves (PR) ratio, defined as the ratio of oil production to beginning of year oil reserves, is assumed to be a function of the natural log of successful developmental drilling and the ratio of reserve revisions to the number of successful development wells drilled. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The estimation allows for region specific intercepts.

(D-26)

$$\ln\left(\frac{PR_{r,k,t}}{1-PR_{r,k,t}}\right) = \sum_{r=1}^{6} \alpha 0_{r,k} * REGr + \alpha 1_k * REVISIONS\_PER\_WELL_{r,k,t} + \alpha 2_k * \ln SW3_{r,k,t}$$

$$+ \rho_k * \ln\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right) - \rho_k * (\sum_{r=1}^{6} \alpha 0_{r,k} * REGr + \alpha 1_k * REVISIONS\_PER\_WELL_{r,k,t-1}$$

$$+ \alpha 2_k * \ln SW3_{r,k,t-1})$$

for r = 1 through 6 and k = 1 (oil).

```
Dependent Variable: ln(PR_{r,1,t}/(1-PR_{r,1,t}))
Number of observations = 108

        Mean of dep. var. = -2.14611            R-squared = .958028
   Std. dev. of dep. var. = .314726    Adjusted R-squared = .954636
 Sum of squared residuals = .444845          LM het. test = 2.27812 [.131]
    Variance of residuals = .449338E-02       Durbin-Watson = 2.31934 [<.994]
 Std. error of regression = .067033
```

		Standard		
Parameter	Estimate	Error	t-statistic	P-value
$\alpha 0_{1,1}$	-2.43406	.342062	-7.11585	[.000]
$\alpha 0_{2,1}$	-2.14204	.160423	-13.3525	[.000]
$\alpha 0_{3,1}$	-2.38258	.214144	-11.1260	[.000]
$\alpha 0_{4,1}$	-2.94240	.198909	-14.7927	[.000]
$\alpha 0_{5,1}$	-2.77332	.245255	-11.3079	[.000]
$\alpha 0_{6,1}$	-2.95383	.221416	-13.3406	[.000]
$\alpha 1_1$	.091517	.025010	3.65922	[.000]
$\alpha 2_1$	.048324	.023466	2.05931	[.039]
ρ_1	.880020	.071250	12.3511	[.000]

Onshore Lower 48 Conventional Natural Gas Production to Reserves (PR) Ratio Equation

The conventional natural gas production to reserves (PR) ratio, defined as the ratio of conventional natural gas production to beginning of year conventional natural gas reserves, is assumed to be a function of the natural log of successful conventional natural gas developmental drilling, natural gas reserve revisions per successful development well drilled, natural gas reserve additions (new field discoveries plus extensions) per successful development well drilled, the natural log of successful development wells drilled, and a dummy variable to account for a change in the calculation of natural gas production for regions 2 and 4 in 2004. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5. The estimation allows for region specific intercepts.

(D-27)

$$\ln\left(\frac{PR_{r,k,t}}{1-PR_{r,k,t}}\right) = \sum_{r=1}^{6} \alpha0_{r,k} * REGr + \alpha1_k * REVISIONS\_PER\_WELL_{r,k,t} + \alpha2_k * DUM\_REG24$$

$$+ \alpha3_k * RESADD\_PER\_WELL_{r,k,t} + \alpha4_k * \ln SW3_{r,k,t} + \rho_k * \ln\left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)$$

$$- \rho_k * (\sum_{r=1}^{6} \alpha0_{r,k} * REGr + \alpha1_k * REVISIONS\_PER\_WELL_{r,k,t-1} + \alpha2_k * DUM\_REG24$$

$$+ \alpha3_k * RESADD\_PER\_WELL_{r,k,t-1} + \alpha4_k * \ln SW3_{r,k,t-1})$$

for r = 1 through 6 and k = 2 & 3 (conventional shallow and deep natural gas).

```
Dependent Variable: ln(PR_r,2&3,t/(1-PR_r,2&3,t))
Number of observations = 102

        Mean of dep. var. = -2.21778              R-squared = .931920
   Std. dev. of dep. var. = .398649     Adjusted R-squared = .924439
 Sum of squared residuals = 1.09358           LM het. test = 1.33845 [.247]
     Variance of residuals = .012017        Durbin-Watson = 2.18371 [<.980]
 Std. error of regression = .109624
```

Parameter	Estimate	Standard Error	t-statistic	P-value
$\alpha0_{1,2\&3}$	-3.10882	.289334	-10.7447	[.000]
$\alpha0_{2,2\&3}$	-2.40467	.337556	-7.12376	[.000]
$\alpha0_{3,2\&3}$	-2.82057	.318842	-8.84628	[.000]
$\alpha0_{4,2\&3}$	-2.49732	.285467	-8.74819	[.000]
$\alpha0_{5,2\&3}$	-3.33491	.345818	-9.64353	[.000]
$\alpha0_{6,2\&3}$	-2.39950	.162027	-14.8092	[.000]
$\alpha1_{2\&3}$	.829007E-04	.246515E-04	3.36291	[.001]
$\alpha2_{2\&3}$	.052320	.027436	1.90699	[.057]
$\alpha3_{2\&3}$	.294641E-04	.152410E-04	1.93322	[.053]
$\alpha4_{2\&3}$	.076172	.041289	1.84485	[.065]
$\rho_{2\&3}$	.693567	.089510	7.74845	[.000]

Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Tight Sands Natural Gas

The production to reserves (PR) ratio for tight sands natural gas, defined as the ratio of tight sands natural gas production to beginning of year tight sands natural gas reserves, is assumed to be a function of the contemporaneous and lagged values of the ratio of tight sands natural gas reserve additions to beginning of year tight sands natural gas reserves. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using unbalanced data for 31 tight sands plays over the 1997-2004 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

$$(D-28)$$

$$
\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right) = \alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t} + \alpha 2_k * RA\_RATIO_{p,k,t-1} + \rho_k * \ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right)
$$
$$
- \rho_k * (\alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t-1} + \alpha 2_k * RA\_RATIO_{p,k,t-2})
$$

for p = 1 through 31 and k = 4 (tight sands natural gas).

```
Dependent variable: ln(PR_p,4,t/(1-PR_p,4,t))
Number of observations = 178

       Mean of dep. var. = -2.32742          R-squared = .815451
   Std. dev. of dep. var. = .540829   Adjusted R-squared = .812269
 Sum of squared residuals = 9.56401         LM het. test = .103186 [.748]
    Variance of residuals = .054966      Durbin-Watson = 1.72267 [<.054]
 Std. error of regression = .23444
```

| | | Standard | | |
Parameter	Estimate	Error	t-statistic	P-value
$\alpha 0_4$	-2.47345	.079514	-31.1069	[.000]
$\alpha 1_4$	.495388	.097745	5.06814	[.000]
$\alpha 2_4$	-.144926	.049234	-2.94364	[.003]
ρ_4	.778747	.052683	14.7818	[.000]

Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Gas Shales

The production to reserves (PR) ratio for gas shales, defined as the ratio of gas shales production to beginning of year gas shales reserves, is assumed to be a function of the contemporaneous value of the ratio of gas shales reserve additions to beginning of year gas shales reserves. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using data for 5 gas shales plays over the 1998-2003 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

(D-29)

$$\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right) = \alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t} + \rho_k * \ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right) - \rho_k * (\alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t-1})$$

for p = 1 through 5 and k = 5 (gas shales).

```
Dependent variable: ln(PR_{p,5,t}/(1-PR_{p,5,t}))
Number of observations:  29

        Mean of dep. var. = -2.10552          R-squared = .887558
   Std. dev. of dep. var. = .768375  Adjusted R-squared = .878908
Sum of squared residuals = 1.98627       Durbin-Watson = 1.34175
    Variance of residuals = .076395        Schwarz B.I.C. = 7.60181
Std. error of regression = .276397       Log likelihood = -2.55087


                          Standard
Parameter  Estimate       Error       t-statistic   P-value
α0_5        -2.39273      .187478      -12.7627      [.000]
α1_5         .527364      .083357       6.32657      [.000]
ρ_5          .870551      .067910      12.8192       [.000]
```

Onshore Lower 48 Production to Reserves (PR) Ratio Equation for Coalbed Methane

The production to reserves (PR) ratio for coalbed methane, defined as the ratio of coalbed methane production to beginning of year coalbed methane reserves, is assumed to be a function of the contemporaneous value of the ratio of coalbed methane reserve additions to beginning of year coalbed methane reserves and the contemporaneous number of successful coalbed methane wells drilled. Because the PR ratio is a variable that must lie between zero and one, the dependent variable is defined as the logistical transformation of the PR ratio. The equation was estimated using data for 11 coalbed methane plays over the 1998-2003 time period with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 4.5.

$$
\ln\left(\frac{PR_{p,k,t}}{1-PR_{p,k,t}}\right) = \alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t} + \alpha 2_k * SW_{p,k,t} + \rho_k * \ln\left(\frac{PR_{p,k,t-1}}{1-PR_{p,k,t-1}}\right)
$$
$$
- \rho_k * (\alpha 0_k + \alpha 1_k * RA\_RATIO_{p,k,t-1} + \alpha 2_k * SW_{p,k,t-1})
$$

(D-30)

for p = 1 through 11 and k = 6 (coalbed methane)

```
Dependent variable: ln(PR_p,6,t/(1-PR_p,6,t))
Number of observations:  65

        Mean of dep. var. = -2.08662          R-squared = .852772
   Std. dev. of dep. var. = .584389   Adjusted R-squared = .844112
 Sum of squared residuals = 2.75815        LM het. test = 2.67810 [.102]
    Variance of residuals = .054081      Durbin-Watson = 1.87761 [<.476]
 Std. error of regression = .232554

                                  Standard
Parameter               Estimate    Error     t-statistic   P-value
α0₆                     -2.45649    .141236    -17.3927      [.000]
α1₆                      .333254    .061970     5.37763      [.000]
α2₆                      .285353E-03 .530457E-04 5.37939     [.000]
ρ₆                       .784110    .066556    11.7813       [.000]
```

Onshore Lower 48 Equation for Tight Sands Natural Gas Wells

The dependent variable in the estimating equation is the ratio of successful tight sands gas wells drilled to the total number accessible tight sands gas wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, the profitability of the play, and a proxy for total E&D spending.

(D-31)

$$WELLSRATIO_{p,k,t} = b0_k + b1_k * CUM\_RATIO_{p,k,t} + b2_k * NET\_PROFIT_{p,k,t} + b3_k * US\_ED\_97$$

for $k = 4$ (tight sands).

```
Dependent variable: WELLSRATIO_{p,4,t}

Number of observations = 336   Schwarz B.I.C. = -458.012
Number of positive obs. = 249  Log likelihood = 469.646
Fraction of positive obs. =    0.741071

                              Standard
Parameter       Estimate       Error       t-statistic    P-value
b0_4           -.023639      .513810E-02    -4.60075      [.000]
b1_4            .114494      .779810E-02    14.6823       [.000]
b2_4            .340047E-02  .527367E-03     6.44802      [.000]
b3_4            .521823E-06  .132872E-06     3.92727      [.000]
σ               .030561      .137479E-02    22.2294       [.000]
```

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

Onshore Lower 48 Equation for Gas Shales Wells

The dependent variable in the estimating equation is the ratio of successful gas shales wells drilled to the total number accessible gas shales wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, a proxy for industry E&D spending, and the profitability of the play.

(D-32)

$$WELLSRATIO_{p,k,t} = b0_k + b1_k * CUM\_RATIO_{p,k,t} + b2_k * NET\_PROFIT_{p,k,t} + b3_k * US\_ED\_97$$

for k = 5 (gas shales).

```
Dependent variable: WELLSRATIO_{p,5,t}

Number of observations = 104   Schwarz B.I.C. = -87.7557
Number of positive obs. = 47   Log likelihood = 97.0445
Fraction of positive obs. =      0.451923


                              Standard
 Parameter       Estimate       Error        t-statistic    P-value
 b0_5          -.464386E-02  .821758E-02    -.565113        [.572]
 b1_5           .030603      .014201         2.15502        [.031]
 b2_5           .016466      .343806E-02     4.78936        [.000]
 b3_5           .187086E-06  .213797E-06     .875063        [.382]
 σ              .022368      .236527E-02     9.45666        [.000]
```

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

Onshore Lower 48 Equation for Coalbed Methane Wells

The dependent variable in the estimating equation is the ratio of successful coalbed methane wells drilled to the total number accessible coalbed methane wells. Because the number of wells in some of the various plays is zero, the equation was estimated using the Tobit procedure in TSP version 4.5. Independent variables in the regression include a measure of the maturity of the play, the profitability of the play, and a proxy for industry E&D spending,

(D-33)

$$WELLSRATIO_{p,k,t} = b0_k + b1_k * CUM\_RATIO_{p,k,t} + b2_k * NET\_PROFIT_{p,k,t} + b3_k * US\_ED\_97$$

for k = 6 (coalbed methane).

```
Dependent variable: WELLSRATIO

Number of observations = 232  Schwarz B.I.C. = -233.148
Number of positive obs. = 131  Log likelihood = 244.042
Fraction of positive obs. =   0.564655


                                Standard
 Parameter        Estimate        Error    t-statistic     P-value
 b0₆             .669034E-02   .636868E-02   1.05051        [.293]
 b1₆             .069564       .997325E-02   6.97510        [.000]
 b2₆             .013832       .138241E-02  10.0059         [.000]
 b2₆             .557494E-06   .156996E-06   3.55101        [.000]
 σ               .027652       .173971E-02  15.8946         [.000]
```

The parameter σ is the estimated standard deviation of the residual. It is necessary to have this estimate for prediction in the context of the Tobit model.

Onshore Lower 48 Regional Associated Dissolved Gas Equations

Associated Dissolved Gas Production

The production of associated dissolved gas was assumed to be a function of the previous year's production and end-of year reserves and oil production from the current year. The equation was estimated using Eviews.

<div align="right">(D-34)</div>

$$Q\_ADGAS_{r,t} = e^{\alpha 0_r} * Q\_ADGAS_{r,t-1}^{\alpha 1} * R\_ADGAS_{r,t-1}^{\alpha 2} * OILPRD_{r,t}^{\alpha 3}$$

for r = 1 through 6 and k = 1 (oil).

```
 Dependent variable: Q_ADGAS
```

Parameter	Estimate	Standard Error	t-statistic	P-value
$\alpha 0_5$	-0.051486			
$\alpha 0_6$	-.156821			
$\alpha 1$	0.714167			
$\alpha 2$	0.113347			
$\alpha 3$	0.138403			

Associated Dissolved Gas Reserve Additions

Reserve additions of associated dissolved gas are forecasted from the parameters of an estimating equation in which the ratio of gross end-of-year reserves to beginning-of-year reserves for associated dissolved gas is assumed to be a function of the ratio of gross end-of-year reserves to beginning-of-year reserves for crude oil and region-specific dummy variables. The equation is estimated in log-linear form with corrections for cross-sectional heteroscedasticity using TSP version 4.5.

<div align="right">(D-35)</div>

$$RA\_ADGAS_{r,t} = \beta 0 + \beta 1 * NRD_{r,t} + \beta 2 * EXTENSIONS_{r,t} + \beta 3 * REVISIONS_{r,t}$$

for r = 1 through 6 and k = 1 (oil).

```
 Dependent variable: RA_ADGAS
 Number of observations:  150
```

Parameter	Estimate	Standard Error	t-statistic	P-value
$\beta 0$	78.8486			
$\beta 1$	1.34968			
$\beta 3$	1.39759			
$\beta 3$	0.592806			

Price Elasticities of Short Run Supply

As noted in chapter 4, the PMM and NGTDM calculate production levels through the use of short-run supply functions that require estimates of the price elasticities of supply. The section below documents the estimations.

Onshore Lower 48 Oil

Price elasticities were estimated using the AR1 technique in TSP which corrects for serial correlation using the maximum likelihood iterative technique of Beach and MacKinnon (1978). Equations for onshore regions 1 and 6 were estimated separately due to the regions' unique characteristics. The functional form is given by:

$$LCRUDE_t = a0 + a1 * LOILRES_t + a2 * LPOIL_t + \rho * LCRUDE_{t-1}$$
$$- \rho * (a0 + a1 * LOILRES_{t-1} + a2 * LPOIL_{t-1})$$

(D-36)

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year oil reserves
LPOIL	=	natural log of the regional wellhead price of oil in 1987 dollars
Δ	=	autocorrelation parameter
t	=	year.

Region 1

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-.977125	.680644	-1.43559
LOILRES	.814563	.114311	7.12584
LPOIL	.08385	.040682	2.06115
Δ	.334416	.297765	1.12309

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 3.03941
 Std. dev. of dependent var. = .365187
    Sum of squared residuals = .015765
        Variance of residuals = .157651E-02
    Std. error of regression = .039705
                  R-squared = .990477
          Adjusted R-squared = .988573
     Durbin-Watson statistic = 1.58775
  F-statistic (zero slopes) = 502.556
 Log of likelihood function = 25.1414

(Statistics based on original data)
  Mean of dependent variable = 4.43559
 Std. dev. of dependent var. = .142410
    Sum of squared residuals = .015832
        Variance of residuals = .158323E-02
    Std. error of regression = .039790
                  R-squared = .936035
          Adjusted R-squared = .923242
     Durbin-Watson statistic = 1.57879
```

Region 6

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	6.69155	2.14661	3.11727
LOILRES	-.123763	.255535	-.484329
LPOIL	.031845	.038040	.837163
Δ	.833915	.135664	6.14691

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 13

Dependent variable:  LCRUDE
(Statistics based on transformed data)
  Mean of dependent variable = 1.13005
 Std. dev. of dependent var. = .605103
    Sum of squared residuals = .013218
        Variance of residuals = .132176E-02
    Std. error of regression = .036356
                   R-squared = .997230
          Adjusted R-squared = .996676
     Durbin-Watson statistic = .896816
   F-statistic (zero slopes) = 1657.10
  Log of likelihood function = 25.7519

(Statistics based on original data)
  Mean of dependent variable = 5.78242
 Std. dev. of dependent var. = .061666
    Sum of squared residuals = .014455
        Variance of residuals = .144552E-02
    Std. error of regression = .038020
                   R-squared = .707387
          Adjusted R-squared = .648864
     Durbin-Watson statistic = .892422
```

For onshore regions 2 through 5, the data were pooled and regional dummy variables were used to allow the estimated production elasticity to vary across the regions. Region 2 is taken as the base region. The form of the equation is given by:

$$
\begin{aligned}
LCRUDE_t = {} & a0 + a1*LOILRES_t + a2*LPOIL_t + a3*LPDUM3_t + a4*LPDUM4_t \\
& + a5*LPDUM5_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} \\
& + a2*LPOIL_{t-1} a3*LPDUM3_{t-1} + a4*LPDUM4_{t-1} + a5*LPDUM5_{t-1})
\end{aligned}
\tag{D-37}
$$

where,

LPDUMr	=	DUMr*LPOIL
DUMr	=	a dummy variable that equals 1 if region=r and 0 otherwise
r	=	onshore regions 2 through 5
Δ	=	autocorrelation parameter
t	=	year.

Regions 2 through 5

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	1.38487	.646290	2.14279
LOILRES	.549313	.077877	7.05360
LPOIL	.105051	.032631	3.21932
LPDUM3	-.077217	.034067	-2.26660
LPDUM4	-.028657	.034318	-.835047
LPDUM5	-.089397	.032700	-2.73387
Δ	.867072	.080470	10.7751

```
SAMPLE:  1978 to 1990
NUMBER OF OBSERVATIONS = 52

Dependent variable:  LCRUDE

(Statistics based on transformed data)
  Mean of dependent variable = .936528
 Std. dev. of dependent var. = .612526
    Sum of squared residuals = .109259
        Variance of residuals = .237519E-02
    Std. error of regression = .048736
                  R-squared = .994731
          Adjusted R-squared = .994159
     Durbin-Watson statistic = 1.42150
   F-statistic (zero slopes) = 1602.00
  Log of likelihood function = 83.7253

(Statistics based on original data)
  Mean of dependent variable = 5.93153
 Std. dev. of dependent var. = .428916
    Sum of squared residuals = .110274
        Variance of residuals = .239725E-02
    Std. error of regression = .048962
                  R-squared = .988524
          Adjusted R-squared = .987277
     Durbin-Watson statistic = 1.40740
```

The estimated coefficient on LPOIL is the price elasticity of crude oil production for region 2. The elasticity for region r (r = 3,4,5) is obtained by adding the coefficient on LPDUM$_r$ to the coefficient on LPOIL.

Offshore Gulf of Mexico Crude Oil

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + a3*LCRUDE(-1) + a4*DUM \qquad \text{(D-38)}$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year oil reserves
LPOIL	=	natural log of the regional wellhead price of oil in 1987 dollars
LCRUDE(-1)	=	natural log of crude oil production in the previous year
DUM	=	a dummy variable that equals 1 for years after 1986 and 0 otherwise.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	-6.48638	2.65947	-2.43897
LOILRES	.821851	.313405	2.62233
LPOIL	.115556	.051365	2.24969
LCRUDE(-1)	.974244	.137890	7.06538
DUM	.079112	.045683	1.73175

```
SAMPLE:  1978 to 1991
NUMBER OF OBSERVATIONS = 14


Dependent variable:  LCRUDE
 Mean of dependent variable = 5.65758
Std. dev. of dependent var. = .106897
   Sum of squared residuals = .021640
       Variance of residuals = .240446E-02
   Std. error of regression = .049035
                 R-squared = .854325
         Adjusted R-squared = .789581
    Durbin-Watson statistic = 1.47269
               Durbin's h = 1.04017
     Durbin's h alternative = .725714
 F-statistic (zero slopes) = 13.1954
 Schwarz Bayes. Info. Crit. = -5.52974
 Log of likelihood function = 25.4407
```

Pacific Offshore Crude Oil

Price elasticities were estimated using the AR1 procedure in TSP which corrects for first order serial correlation using a maximum likelihood iterative technique. The regression equation is given by:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1}$$
$$- \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1}) \qquad \text{(D-39)}$$

where,

LCRUDE	=	natural log of crude oil production
LOILRES	=	natural log of beginning of year crude oil reserves
LPOIL	=	natural log of the regional wellhead price of crude oil in 1987 dollars
Δ	=	autocorrelation parameter
t	=	year.

Results

Variable	Estimated Coefficient	Standard Error	t-statistic
a0	1.34325	.443323	3.02995
LOILRES	.310216	.067090	4.62390
LPOIL	.181190	.067391	2.68865
Δ	-.355962	.320266	-1.11146

```
SAMPLE:  1977 to 1991
NUMBER OF OBSERVATIONS = 15

Dependent variable:  LCRUDE
(Statistics based on transformed data)
        Mean of dependent variable = 5.31728
      Std. dev. of dependent var. = .646106
         Sum of squared residuals = .209786
             Variance of residuals = .017482
         Std. error of regression = .132220
                        R-squared = .971382
               Adjusted R-squared = .966613
           Durbin-Watson statistic = 1.61085
         F-statistic (zero slopes) = 161.152
        Log of likelihood function = 10.6711

(Statistics based on original data)
        Mean of dependent variable = 4.001171
      Std. dev. of dependent var. = .231415
         Sum of squared residuals = .220359
             Variance of residuals = .018363
         Std. error of regression = .135511
                        R-squared = .711359
               Adjusted R-squared = .663252
           Durbin-Watson statistic = 1.61258
```

Conventional Western Canada Equations

Successful Gas Wells

The equation to forecast successful gas wells in Western Canada was estimated for the time period 1978-2004 using aggregated wells and production data for the Western Canadian provinces of Alberta, British Columbia and Saskatchewan and price data for Western Canada as a whole. The form of the estimating equation is given by:

(D-40)

$$\ln GWELLS_t = \beta 0 + \beta 1 * \ln GPRICE_t + \beta 2 * REMAIN_t + \beta 3 * PR_{t-1}$$

where lnGWELLS is the natural log of successful gas wells drilled in Western Canada, lnGPRICE is the natural log of real Western Canada gas price in 2000 US$ per thousand cubic feet, REMAIN is the remaining undiscovered recoverable resources in the region at the beginning of the year, and PR is the realized production-to-reserve ratio from the previous year. The equation was estimated using version 4.4 of the econometric software package TSP. Parameter estimates and regression diagnostics are given below.

Method of estimation = Ordinary Least Squares

```
Dependent variable: lnGWELL
Current sample:  32 to 58  (1978 B 2004)
Number of observations:  27

        Mean of dep. var. = 8.16671      LM het. test = 1.77670 [.183]
  Std. dev. of dep. var. = .729120      Durbin-Watson = 1.81515 [<.518]
Sum of squared residuals = 1.87931  Jarque-Bera test = 7.49640 [.024]
    Variance of residuals = .081709   Ramsey's RESET2 = .431708 [.518]
Std. error of regression = .285848    F (zero slopes) = 48.7206 [.000]
              R-squared = .864035      Schwarz B.I.C. = 8.92640
     Adjusted R-squared = .846301      Log likelihood = -2.33472

             Estimated      Standard
Variable    Coefficient      Error        t-statistic    P-value
B0          3.95973        1.13712        3.48224        [.002]
LNPGAS      .506617        .140252        3.61219        [.001]
REMAIN      .116340E-04    .558701E-05    2.08233        [.049]
PR_LAG      33.7870        5.89647        5.73003        [.000]
```

Finding Rate

The equation to forecast the average natural gas finding rate in Western Canada was estimated for the time period 1965-2005 using aggregated reserves and production data for the Western Canadian provinces of Alberta, British Columbia and Saskatchewan. The form of the estimating equation is given by:

(D-41)

$$\ln FR_t = \beta 0 + \beta 1 * REMAIN_t - \rho * (\beta 0 + \beta 1 * REMAIN_{t-1})$$

where lnFR is the natural log of gas reserves added per successful gas well drilled in Western Canada and REMAIN is the remaining undiscovered recoverable resources in the region at the beginning of the year. The equation was estimated using version 4.4 of the econometric software package TSP. Parameter estimates and regression diagnostics are given below.

Method of estimation = Ordinary Least Squares

```
Dependent variable: LNFR
Current sample:  19 to 59 (1965-2005)
Number of observations:  41

        Mean of dep. var. = .302207          R-squared = .536443
  Std. dev. of dep. var. = 1.01899  Adjusted R-squared = .512045
Sum of squared residuals = 19.2569      Durbin-Watson = 2.20659
    Variance of residuals = .506761      Schwarz B.I.C. = 48.3075
Std. error of regression = .711872      Log likelihood = -42.7371

                        Standard
Parameter  Estimate      Error       t-statistic    P-value
B0         -2.43218     .672676      -3.61567       [.000]
REMAIN     .166026E-04  .394186E-05   4.21186       [.000]
RHO        .384096      .142863       2.68856       [.007]
```