DOE/EIA-M063(98)

# Documentation of the
# Oil and Gas Supply Module (OGSM)

January 1998

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

# ERRATA

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Equations 10 and 12 on pages 4-C-8 and 4-C-10, respectively, in Appendix 4-C are incorrect. The correct equations are as follows:

Equation 10

$$QTECH_t = Q * (1 + TECH)^{t-T} \qquad (1)$$

where,

| | | |
|---|---|---|
| Q | = | initial resource estimate in year T |
| TECH | = | annual percentage expansion of resource base due to technological change. |

Equation 12

$$\delta 1_{r,k,t} = \frac{FR1_{r,k,t-1}(1+\beta 1) - FRMIN1_{r,k}}{Q^{E}_{r,k} * (1+TECH)^{t-T} - \sum_{T+1}^{t-1} \int FR1_{r,k,t} d(SW1)} \qquad (2)$$

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We regret any inconvenience this may have caused.

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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 natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes enhanced oil recovery (EOR), and unconventional gas recovery (UGR) from tight gas formations, Devonian/Antrim shale 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 trade in natural gas, imports and exports by entry region. Foreign gas trade may occur via either pipeline (Canada or Mexico), or via transport ships as liquefied natural gas (LNG). 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 Natural Gas Transmission and Distribution Module (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 GNP(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. NGTDM employs short-term supply functions, the parameters for which are provided by OGSM for nonassociated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. The short-term supply functions reflect potential oil or gas flows to the market for a one 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 and resultant emissions are forwarded to the Systems Module. Forecasts of oil and gas production, go 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 NEMS98. The version is that used to produce the *Annual Energy Outlook 1998 (AEO98)*. 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
- Model overview and rationale
- Model structure
- Inventory of input data, parameter estimates, and model output
- Detailed mathematical description.

# 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 forecasts of crude oil, 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). The OGSM does not provide nonassociated gas production forecasts per se, but rather parameter estimates for short-term domestic gas production functions that reside in the NGTDM.

The NGTDM utilizes the OGSM supply functions during a solution process that determines regional wellhead market-clearing prices and quantities. After equilibration is achieved in each forecast year, OGSM calculates revised parameter estimates for the supply functions for the next year of the forecast based on equilibrium prices from the PMM and NGTDM and natural gas quantities received from the NGTDM. OGSM then sends the revised parameters to NGTDM, which updates the short-term supply functions for use in the following forecast year. The determination of the projected natural gas and crude oil wellhead prices and quantities supplied occurs within the NGTDM and OGSM. As the supply component only, OGSM cannot project prices, which are the outcome of the equilibration of demand and supply. The basic interaction between OGSM and the other oil and gas modules is represented in Figure 1. Controlling information and expectations come from the System Module. Major exogenous inputs include resource levels, finding rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the oil and gas supply outlook of the OGSM.

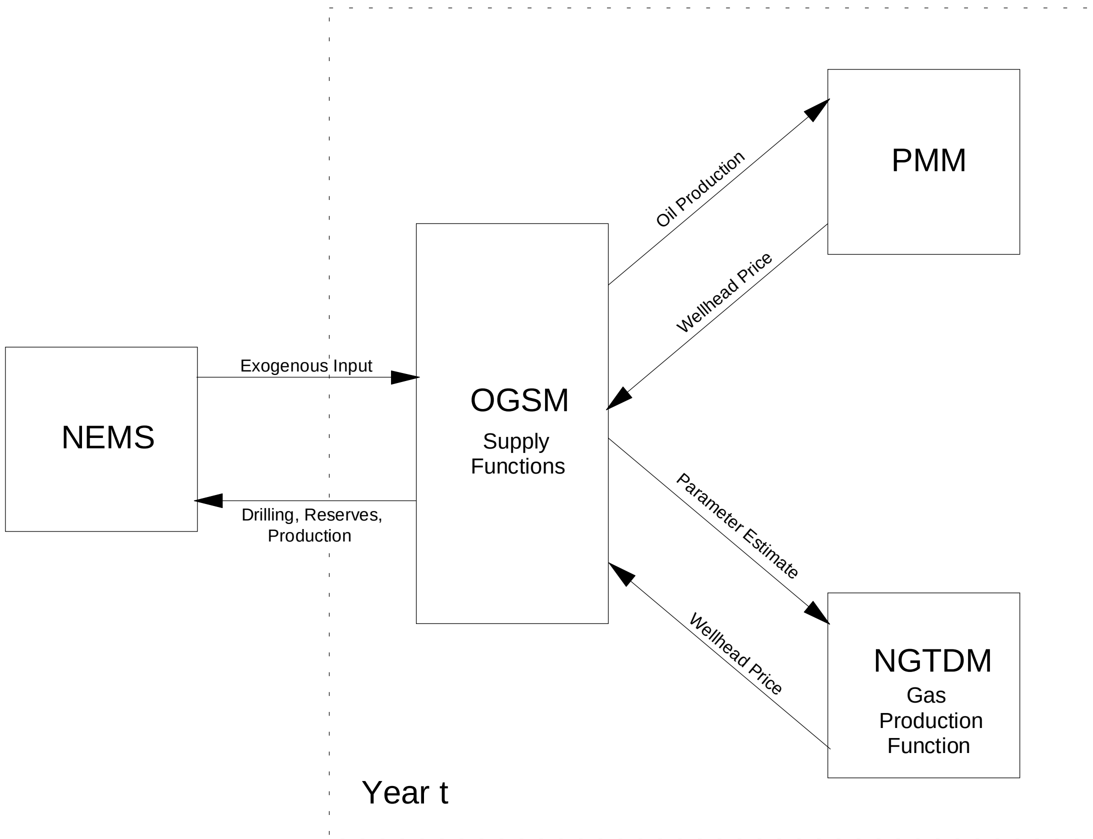
OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply comprises production from conventional and enhanced oil recovery techniques. Natural gas is differentiated by nonassociated and associated-dissolved gas.[1] Nonassociated natural gas is categorized by conventional and unconventional types. Conventional natural gas recovery is differentiated by depth between formations up to 10,000 feet and those at greater than 10,000 feet (in the context of OGSM, these depth categories are referred to as shallow or deep). The unconventional gas category in OGSM consists of resources in tight sands, Devonian/Antrim shale, and coal bed methane formations.

OGSM provides mid-term (15 to 25 year) forecasts, as well as serving as an analytical tool for the assessment of various policy alternatives. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues 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,

[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 1. OGSM Interface with Other Oil and Gas Modules**




- 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.

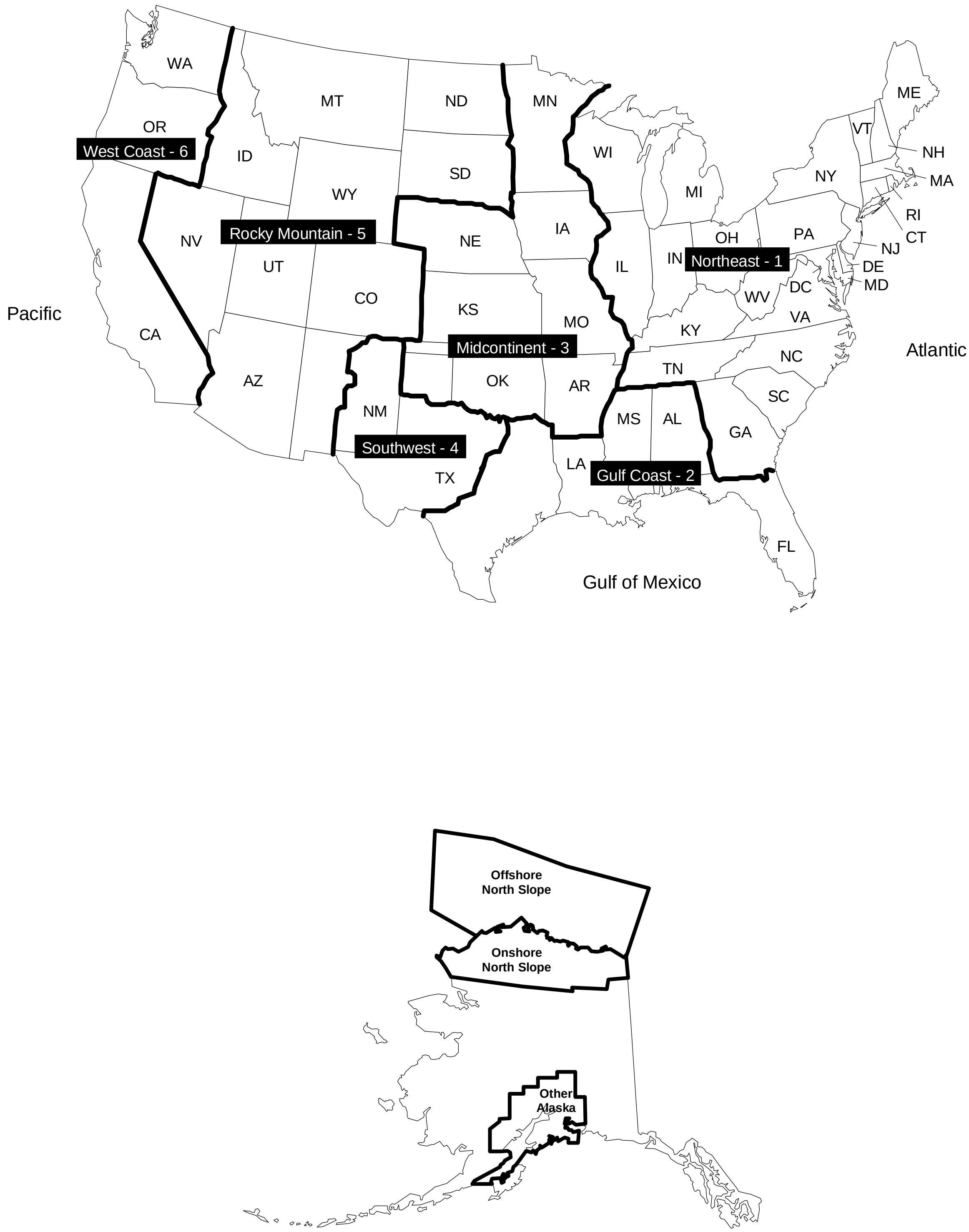
OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for economically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). This feature allows the model to be used for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

- the uncertainty surrounding the economically 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 will be used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

**Figure 2. Oil and Gas Supply Regions**



# 3. Model Rationale and Overview

## Introduction

This chapter provides a brief overview of the rationale and theoretical underpinnings of the methodology chosen for the Oil and Gas Supply Module (OGSM). First a classification of previous oil and gas supply modeling methodologies is discussed, with descriptions of relevant supply models and comments on their advantages and disadvantages. This leads to a discussion of the rationale behind the methodology adopted for OGSM and its various submodules, including the onshore and offshore Lower 48 states, the foreign natural gas supply submodule, and the Alaska submodule.

## Overview of Oil and Gas Supply Modeling Methods

Oil and gas supply models have relied on a variety of techniques to forecast future supplies. These techniques can be categorized generally as geologic/engineering, econometric, "hybrid" -- an approach that combines geologic and econometric techniques, and market equilibrium. The geologic/engineering models are further disaggregated into play analysis models and discovery process models.

### Geologic/Engineering Models

#### *Play Analysis*

According to the U.S. Geological Survey (USGS), a play is a group of geologically related, known or undiscovered accumulations (prospects) having similar hydrocarbon sources, reservoirs, traps, and geologic histories. A prospect is a geologic feature having the potential for the trapping and accumulation of hydrocarbons. Prospects are the targets of exploratory drilling. Play analysis relies on detailed geologic data and subjective probability assessments of the presence of oil and gas. Seismic information, expert assessments, and information from analog areas are combined in a Monte Carlo simulation framework to generate a probability distribution of the total volume of oil or gas present in the play. These models are primarily used as a source assessment tool, but they have been used with an economic component to generate oil and gas reserve additions and production forecasts.

An example of a play analysis model is EIA's Outer Continental Shelf Oil and Gas Supply Model (OCSM)[1], which was developed during the late 1970s and early 1980s. The OCSM used a field-size-distribution approach to evaluate Federal offshore supply (including production from the Gulf of Mexico, Pacific, and Atlantic offshore regions). The OCSM drew on a series of Monte Carlo models based on the work of Kaufman and Barouch.[2] These models started with lognormal field-size distributions and examined the order in which fields are discovered. The OCSM also drew on an alternative approach taken by Drew et al.,[3] which was an extension of

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[1] *Outer Continental Shelf (OCS) Oil and Gas Supply Model, Volume 1, Model Summary and Methodology Description*, Energy Information Administration, Washington, D.C., December 1982, DOE/EIA-0372/1. and Farmer, Richard D., Harris, Carl M., Murphy, Frederic H., and Damuth, Robert J., "The Outer continental Shelf Oil and gas Supply model of the Energy Information Administration," *North-Holland European Journal Of Operation Research*, 18 (1984), pages 184-197.

[2] Kaufman, G.M., and Barouch, E., "The Interface Between Geostatistical Modeling of Oil and Gas Discovery and Economics," *Mathematical Geology*, 10(5), 1978.

[3] Drew, L.J., Schuenemeyer, J.H., and Bawiec, W.J., *Estimation of the Future Rate of Oil and Gas Discovery in the Gulf of Mexico*, U.S. Geologic Survey Professional Paper, No. 252, Reston, VA, 1982.

the Arps and Roberts approach to resource assessment,[4] falling between simple extrapolation and Monte Carlo simulation. This alternative approach explicitly represented an exponentially declining exploration efficiency factor (in contrast to that of Kaufman and Barouch, in which declining efficiency was related solely to the assumed decline in field size). Under this approach, finding rates for the number of fields in a collection of size categories were estimated (as opposed to determining an aggregate finding rate)--an approach involving massive data requirements.

Key differences between the OCSM and other field-size-distribution models included the fact that OCSM was based on (a) geological data on undiscovered structures obtained from the U.S. Department of the Interior (as opposed to data simulated from aggregate regional information), (b) a highly detailed characterization of the supply process, © a relatively sophisticated treatment of uncertainty, and (d) explicit consideration of investment decisions at the bidding, development, and production stages, in addition to the exploration stage.

Although the OCSM had many superior qualities, it was highly resource intensive. In particular, the OCSM required (a) maintenance of a large database on more than 2000 prospects in thirty offshore plays, (b) considerable mainframe CPU time to execute completely, reflecting the highly complex algorithmic and programming routines, and © maintenance of a wide range of staffing skills to support both the model and the underlying data. Since all these problems violate basic key attributes required of an oil and gas supply model operating in the NEMS environment, adopting a similar play analysis approach for the OGSM was rejected.

### *Discovery Process*

Kaufman, Balcer and Kruyt described discovery process modeling as "building a model of the physics of oil and gas field discovery from primitive postulates about discovery that are individually testable outside the discovery model itself." Unlike play analysis models, discovery process models can only be used in well developed areas where information on exploration activity and oil and gas discovery sizes is readily available. Discovery process models reflect the dynamics of the discovery process and do not require detailed geologic information. They rely instead on historical exploratory drilling and discoveries data.

Although the details of discovery process models vary, they all rely on the assumption that the larger the oil or gas field, the more likely it will be discovered. This assumption leads to discovery rates (the amount of oil or gas found per unit of exploratory effort) that typically decline as more of an area is explored. Discovery process models usually specify a finding rate equation using a functional form such that discoveries decline with cumulative drilling.

Discovery process models have generally been applied to specific geologic basins, such as the Denver-Julesburg basin (Arps and Roberts 1959). They have also been used in studies of the Permian Basin[5] and the North Sea. Discovery process models do not usually incorporate economic variables such as costs, profits, and risk. Returns to exploratory effort are represented in terms of wells drilled or reserves discovered.

Since there are generally no economic components, discovery process models cannot project time paths of future drilling and reserve additions without using ad hoc constraints (for example constraints on rigs or expenditures). The constraints chosen become to some extent deciding factors in the model outcome. Typically factors such as cash flow or the availability of rigs are constrained to enable the model to forecast satisfactorily.

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[4]Arps, J.J., and Roberts, T.G., "Economics of Drilling for Cretaceous Oil on East Flank of Denver-Julesburg Basin," *American Association of Petroleum Geologists Bulletin 42*, 1958.

[5]*Future Supply of Oil and Gas from the Permian Basin of West Texas and Southeastern New Mexico*, U.S. Geological Survey, Washington DC, 1980

The OGSM is intended to support the market analysis requirements of NEMS, thus it includes both an economic and a geologic component. A model of industry activity was developed for the OGSM that predicts expenditure and drilling levels each period of the forecast horizon. The estimated levels of drilling are used to determine oil and gas reserve additions in each period through a finding rate function. The modular nature of OGSM does allow for future consideration of an alternate geologic approach such as a pure discovery process model. Whereas many discovery process models specify one finding rate function, OGSM uses three to capture the varying influences of new field wildcat, other exploratory, and development drilling on the discovery process.

## Econometric Models

Many econometric models do not include a description of geologic trends or characteristics -- for example, average discovery sizes do not vary systematically with cumulative exploratory drilling as in discovery process models. Additionally, these models, for the most part, have not been based on a dynamic optimization model of firm behavior and do not incorporate expectations of future economic variables -- a limitation that also applies, for the most part, to the geologic/engineering models.

Recent econometric models have made some inroads in overcoming these problems. Rational expectations econometric models have been developed by Hendricks and Novales and by Walls which are based on intertemporal optimization principles that incorporate uncertainty and inherently attempt to capture the dynamics of the exploration process.[6] Geologic trends also are accounted for, though not in as much detail as they are in play analysis and discovery process models.

These improvements are not without cost. The theoretical specifications of rational expectations econometric models must be highly simplified in order to obtain analytic solutions to the optimization problems. This feature of these models means that it is impossible to describe the oil supply process with the level of detail that the more *ad hoc* approaches allow. In addition, a long time series of historical data is necessary in order to obtain consistent parameter estimates of these models. Such a time series does not exist in many cases, especially for frontier areas such as the offshore or at the regional levels required for NEMS. Finally, because of the degree of mathematical complexity in the models, forecasting and policy analysis often turn out to be intractable.

Econometric methods have been employed primarily for studies of a single region, either a relatively limited area such as a single state or more broad-based such as the entire Lower 48 states. An example of the former is the work by Griffin and Moroney (1985), which was used to study the effects of a state severance tax in Texas. Recent work on large scale aggregate data appear in studies by Epple (1985) and Walls (1989). These studies link models of individual dynamic optimizing behavior under uncertainty to the use of econometric techniques. In general, the firm is assumed to maximize a quadratic objective function subject to linear constraints on the processes governing the stochastic variables that are outside the firm's control. In the Walls model, an oil exploration firm chooses the number of exploratory wells to drill in each period to maximize the expected discounted present value from exploration, providing a clear link between a theory of the exploration firm's dynamic behavior under uncertainty and the econometric equations of the model. However, in addition to other considerations, the model is so mathematically complicated that "...it is impossible to describe the oil supply process with the same level of detail as the *ad hoc* models. In other words, it is difficult, if not impossible, to model all of the stages of supply in a realistic way."[7] Such a model would not be appropriate for the intended role of NEMS, although it can be quite useful in other applications.

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[6]Hendricks, Kenneth and Alfonso Novales, 1987, Estimation of dynamic investment function in oil exploration, Draft manuscript. Walls, Margaret A., 1989, Forecasting oil market behavior: Rational expectations analysis of price shocks, Paper EM87-03 (Resources for the Future, Washington, D.C.)

[7]Walls, Margaret A., *Modeling and forecasting the supply of oil and gas: A survey of existing approaches*, Resources and Energy 14 (1992), North Holland, p 301.

## Hybrid Models

Hybrid models are an improvement in some ways over both the pure process models and the econometric models. They typically combine a relatively detailed description of the geologic relationship between discoveries and drilling with an econometric component that estimates the response of drilling to economic variables. In this way, a time path of drilling may be obtained without sacrificing an accurate description of geologic trends. Such a hybrid approach has been directly implemented (or incorporated indirectly, using the results of hybrid models) under a variety of methodological frameworks. Such frameworks include the system dynamics methodology used in the FOSSIL2 model, which underlies the recent *National Energy Strategy* and numerous related studies.

The Gas Research Institute's (GRI) Hydrocarbon Supply Model (HSM) is one example of a hybrid model. The HSM employs an enhanced discovery process component to estimate discoveries from the underlying resource base and an economic component to provide costs for exploration, development and production of oil and gas accumulations. Overall industry activity is subject to an econometrically determined financial constraint.

The American Gas Association's Total Energy Resource Analysis model (TERA) employs an econometric approach to determine changes in aggregate Lower 48 onshore drilling based on a profitability index. Offshore Lower 48 supply is evaluated offline for inclusion in the outlook. New supplies flow from discoveries that depend on a finding rate. This finding rate does not rely on an explicit resource estimate, but does reflect resource depletion given cumulative increases in reserves. Technology influences the finding rate, but it primarily manifests itself in lower costs by reducing the number of dry holes experienced in the supply process.

Data Resources Inc's oil and gas supply model also employs a hybrid approach. Lower 48 exploratory drilling depends on projected net revenues. Developmental drilling is a function of lagged exploratory wells. New supplies occur from discoveries that depend on a finding rate. The finding rate itself is based on an analysis of recent trends in observed data. The extrapolative technique used does not incorporate an explicit estimate for economically recoverable resources. Technology is not explicit within the model, but it is treated on an *ad hoc* basis.

## Market Equilibrium Models

Market-equilibrium models connect supply and demand regions via a transportation network and solve for the most efficient regional allocation of quantities and corresponding prices. Market-equilibrium models tend to be single energy market models that concentrate on the economic forces that efficiently balance markets across regions without explicit representation of other fuel market conditions. Consideration of the processes that alter supply and demand are not necessarily modeled in detail; stylized regional supply and demand curves are postulated.

An example of a market-equilibrium model is Decision Focus Incorporated's North American Regional Gas Model (NARG). Regional supplies of indigenous production are based on a representation of the gas resource base as a continuous, ordered stream of reserve increments that will be discovered and developed over a range of prices. As prices rise, thus covering increasing costs, additional portions of the resource base systematically become available to the market. Regional supply curves also reflect an assessment of the expected cost characteristics of the technically recoverable resource base.

Supply regions are linked to demand regions throughout the United States and Canada by a network of existing and prospective pipelines, with specified capacity constraints and tariffs. Within the framework of this model, 17 supply regions are specified: 12 in the United States and 5 in Canada.[8] Each region has its own gas supply curve based on estimates of the resource base and associated costs of discovery and development from the Potential Gas Committee (United States), the Canadian Energy Research Institute, and the Canadian National Energy Board.

The partial equilibrium nature of these models is contrary to the requirements of an oil and gas supply model operating within the integrated environment of NEMS. Moreover, the solution from a market equilibrium model consists of a volume of gas produced, rather than a supply schedule as required by the Natural Gas Transmission and Demand Model. Finally, the forecasting capabilities of this approach are open to question given that many of the key parameters are not subjected to the discipline of validation against historical data.

## OGSM Rationale

None of the models described are able to address all the issues that would be required of the OGSM. For example, some models might have reasonable representations of the onshore supply process, but completely lack an offshore or unconventional fuel component. Some models only provide a representation of the gas supply industry while almost completely ignoring oil supplies. Some models provided only limited ability to be simulated under different fiscal and policy environments. OGSM had to be developed keeping in mind the overall goal of NEMS - the ability to address many of the likely physical and policy variables that might affect future U.S. oil and gas supplies.

An important consideration regarding many of the models discussed above is that they typically tend to be highly resource intensive, both (a) in terms of personnel requirements for development and maintenance and (b) in terms of execution time and other computational resource requirements. It was for these reasons that the OCSM model, the EIA's offshore play-analysis model, was ultimately retired.

Another difficulty with many of these models is that the relationships in the models are typically not subjected to the discipline of validation against historical data--in fact, there are usually too many parameters in the models to estimate econometrically. As a result, the models cannot project time paths of future oil and gas supply without the use of ad hoc constraints that turn out to be important determinants of the forecasts generated by the models.

Accordingly the OGSM uses some features of the discovery-process approach, but does not employ any of the traditional discovery process models discussed earlier because they are too data intensive. The chosen OGSM design helps to satisfy some of the specification requirements set forth for the NEMS,[9] which emphasize, among other attributes, model transparency and model efficiency. The OGSM, as a regionally aggregated discovery-process model, does not determine activity levels on the basis of an explicit economic evaluation of discrete production units, such as individual producing fields (oil and gas from Alaska is the exception). The requirements for performing a disaggregated field analysis were prohibitive in the context of the time and resources needed to develop and maintain such an approach, without necessarily affecting the modeling results appreciably. The OGSM, however, simulates endogenously separate discretionary levels for exploratory and developmental drilling in contrast to the fixed relationship between exploratory and developmental drilling that characterizes many other models.

The Alaska Oil and Gas Supply Submodule (AOGSS) and the liquefied natural gas (LNG) component of the Foreign Natural Gas Supply Submodule (FNGSS) are the exceptions to the above paragraph. Both methodologies

[8]Mexico has been introduced into the model as a net import flow in recent work for the National Petroleum Council's Natural Gas Study.

[9]See, for example, *Requirements for a National Energy Modeling System*, December 1991, and *Recommended Design for the National Energy Modeling System*, October 1991.

take more of an engineering approach. In the case of Alaska this is because of the relative low number of fields (compared to the Lower 48 states) expected to be economically viable in Alaska. The representation of LNG in OGSM is unique because field production is not part of domestic operations. The stages of the LNG process to be modeled primarily concern the receipt of LNG at importation facilities and its subsequent conversion into gaseous natural gas.

The remainder of this section provides a brief discussion of the rationales and methodologies of the OGSM's submodules.

## Lower 48 Oil and Gas Supply

A hybrid econometric/discovery process approach was used to model Lower 48 states conventional oil and gas supply and UGR supply in the OGSM.[10] The geology is represented in the model's discovery-process components, while the economics of exploration, development, and production are captured by the model's econometric equations component. The methodology was designed for two basic purposes: (1) to generate forecasts of future drilling activity, and oil and gas supplies under alternative scenarios and (2) to provide a framework for analyzing the potential impacts of policy changes on future drilling activities and oil and gas supplies. The OGSM was designed to meet these two requirements in a transparent and efficient manner, while simulating the supply behavior of the oil and gas industry and incorporating essential behavioral and physical relationships without resorting to extraordinarily complex functional forms and/or algorithms.

### *Onshore and Shallow Offshore Supply*

Relying on basic research on the determinants of business investment, it is assumed that the industry's level of domestic exploration and developmental drilling is determined by several major factors, including: the expected oil and gas prices, the expected profitability of domestic exploration and developmental drilling and the economic and geologic risk associated with exploration and developmental drilling. The drilling equations are econometrically based. Specifically, the levels of exploration and developmental drilling are forecast on the basis of econometrically estimated equations that relate historical exploration and developmental drilling to the explanatory variables given above.

The econometric approach was chosen over a linear programming approach or a hybrid linear programming/econometric approach of the type used in PROLOG, the OGSM's predecessor, for two major reasons. First, incurring the additional computational burden associated with solving a linear programming problem with multiple constraints seemed inefficient relative to forecasting directly from the estimated historical relationships. This is especially critical given that NEMS requirements include the goals of quick execution and the efficient utilization of computer resources. Second, the linear programming approach requires the explicit specification of the objective function while an econometrically based approach does not. If the true objective function is unknown or cannot be specified without adding undue complexity and computational burden to the model, then an econometric approach is more sensible. For empirical purposes, implementation of the econometric approach does not require specification of an explicit objective function, but only the identification of explanatory variables whose movements can be related, on average, to changes in investment that are driven by a particular behavioral objective, e.g, profit maximization.

The econometric method of determining drilling activity levels on the basis of expected profitability, is certainly in line with the methodologies of several other respected oil and gas supply models. For example, overall industry drilling activity in the Hydrocarbon Supply Model (HSM) of the Gas Research Institute (GRI) is subject to an

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[10]A slightly different approach was employed to represent EOR and deep water offhore supply activities and these methods are described in the following sections.

econometrically determined financial constraint. The Total Energy Resource Analysis (TERA) model of the American Gas Association (AGA) employs an econometric approach to determine changes in aggregate lower 48 onshore drilling based on a profitability index. The DRI/McGraw-Hill (DRI) model forecasts exploratory drilling on the basis of projected net revenues. Though the specific details differ across the models, their unifying trait is an explicit recognition of the important linkages among profitability, exploration and developmental drilling expenditures (financial resources), and drilling activity levels.

The total number of wells drilled for each specific drilling activity is converted to expenditure levels by multiplying the drilling levels by estimates of drilling costs per well, which vary by region and fuel type. Based on historical proportions, exploratory wells are separated into new field wildcats and other exploratory wells. Differentiation between types of exploratory drilling is a feature that is not found in most other hybrid models. It enables the discovery process component to more realistically model the reserves additions process.

Proved reserves comprise the only source for production, and the discovery process is the means by which nonproducing resources (i.e., undiscovered economically recoverable resources or inferred reserves) are converted into proved reserves. The discovery process component in OGSM consists of a set of finding rate equations that relate the volume of reserve additions to drilling levels. Three discovery processes are specified: new field discoveries from new field wildcats, field extension volumes from other exploratory drilling, and reserve revisions due to developmental drilling. New field wildcat discovery volumes are separated into proved and inferred reserves based on the historical relationship between a field's ultimate recovery and its initial discovery size. Inferred reserves are converted into proved reserves in later periods through other exploratory and developmental drilling. This differentiation in finding rates provides a more accurate representation of the reserves discovery process in the oil and gas industry. Exogenous estimates of the undiscovered economically recoverable resource base are incorporated in the new field wildcat finding rates. This allows user assumptions concerning the resource base to be specified for purposes of policy analysis, such as offshore drilling moratoria. The distinction between proved and inferred reserves is also found in GRI's HSM, though the separate impacts of new field wildcats and other exploratory wells on the reserves discovery process is not modeled there.

### *Deep Water Offshore Supply*

While the hybrid econometric/discovery process approach is a significant improvement over purely process models or econometric models, it is still inherently inadequate when if comes to determining exploration and development activity from predominantly frontier areas. This is due to the reliance of the hybrid model on significant historical information being available to forecast future activity based on historical performance. Deep water offshore Gulf of Mexico has become active only during the last five years and very little information to develop equations for the discovery process/econometric type models exists. Due to significant differences in technology, costs, and productivity of fields in the Deep water areas compared to those from shallow water areas, it would be incorrect to extrapolate the data from shallow water areas to the deep water fields.

An alternative, field-based engineering and economic analysis approach allows for the explicit characterization of the undiscovered resource base in the Deep water areas, and the evaluation of the technology options, project scheduling and expenditures for exploration, development and production activities as a function of the water depth and field size. It also makes use of a discounted cash flow algorithm to characterize project profitability. A positive net present value for each prospect is directly associated with the minimum acceptable supply price (MASP) for that prospect.

The production timing algorithm explicitly makes choices for field exploration and development based on relative economics of the project profitability compared with the equilibrium crude oil and natural gas prices determined by PMM and NGTDM in OGSM. Development of inferred (economic) reserves into proved reserves is constrained by drilling activity. Proved reserves are translated into production based on reserves-to-production (R/P) ratio. The drilling activity and the R/P ratio are both determined by extrapolating the historical information.

This approach not only permits analysis of each and individual prospect, but also permits the possibility of looking at the impact of various regulatory, policy, and financial issues by evaluating these impacts at the individual prospect level. Thus, the field-based engineering and economic analysis approach utilized to project supply potential from deepwater offshore Gulf of Mexico OCS significantly enhances OGSM's analytical capabilities. The model, due to its modular construction, can be easily adapted to address other economic issues, and also to address other potential deepwater offshore areas in the future.

#### *Enhanced Oil Recovery Supply*

The Enhanced Oil Recovery Supply Submodule (EORSS) uses a modified form of the previously described methodology, which is used for conventional oil supply and all natural gas recovery types. A more thorough description of the EORSS methodology is presented in Chapter 4 of this report. All submodules in the OGSM share the similar basic attributes, but the representation may differ in the particulars. This section presents a discussion of the general differences between the methodologies.

The basic supply process for both EOR and the other sources of crude oil and natural gas consists of essentially the same stages. The physical stages of the supply process involve the conversion of unproven resources into proved reserves, and then the proved reserves are extracted as flows of production. A key element of economics on the supply side is that investment funds are directed more heavily to exploration and development opportunities that have greater expected profitability.

The significant differences between the methodology of the EORSS and the other submodules of OGSM concern the conversion of unproven resources to proved reserves and the determination of supply activities. The transfer of resource stocks from unproven to proved status in OGSM is handled by use of finding rate functions that relate reserve additions to cumulative drilling levels. The EORSS uses discovery factors that convert a specified fraction of unproven resources into proved reserves. These factors depend on the expected profitability of EOR investment opportunities, and not on drilling levels.

Greater expected financial returns motivate the conversion of larger fractions of the resource base into proved reserves. This is consistent with the principle that funds are directed toward projects with relatively higher returns. An explicit determination of expenditures for supply activities does not occur within the EORSS as it does in the OGSM. Given the role of the discovery factors in the supply process, the implicit working assumption is that EOR investment opportunities with positive expected profit will attract sufficient financial development capital. EOR investment does not compete with other oil and gas opportunities. EOR recovery is sufficiently different, and its product not entirely similar to the less heavy oil most often yielded by conventional projects, that this assumption is considered appropriate.

## Foreign Natural Gas Supply

The Foreign Natural Gas Supply Submodule consists of three key components: Canadian gas trade, liquefied natural gas (LNG) trades and gas trade with Mexico. Different methodological approaches were taken for each component in recognition of inherent differences between the various modes of import and the different circumstances affecting both supply capacity in the source country and its potential availability to the United States. The process by which Canadian gas flows to the United States is essentially the same process as that for U.S. supplies in the Lower 48 states. LNG imports are very different however, with available regasification capacity and the unit costs of transportation, liquefaction, and regasification being the most important determinants of import volumes. Production costs in countries currently or potentially providing LNG are a relatively small portion of total unit costs for gas delivered into the U.S. transmission network. Gas has not been imported from Mexico in the eight year period ending in 1992. Mexico began exporting very small volumes of gas to the United States in 1993. Further development of Mexican gas production capability depends more on institutional rather than economic factors. Consequently a third, scenario-based approach was chosen to model gas imports from this source.

It is a recursive type model, with oil and gas prices as the principal driving variables. Regional oil and gas prices are determined exogenously from the OGSM and are received from the Petroleum Market Module and the Natural Gas Transmission and Distribution Module respectively.

### *Canadian Gas Imports*

Gas imports from Canada are modeled using a hybrid approach similar to the one taken for the Lower 48 States. The model has two key components, a discovery process component and an economic component. The economic component forecasts drilling activity as a function of discounted cash flows constructed for a representative Canadian oil and gas project. Within the DCF, variables such as prices, flow rates, costs, and taxes are specified and can be manipulated for analysis purposes. The discovery process component relates reserve additions per period to wells drilled.

A hybrid method was chosen for modeling Canadian gas supplies since this approach most effectively meets the numerous analytical requirements of OGSM. Also, sufficient data are available for the Canadian oil and gas industry. Finally, although this approach is a somewhat simplified version of the Lower 48 methodology, the two models are methodologically consistent.

### *Liquefied Natural Gas*

LNG has been included as an explicit element of some natural gas models. LNG is represented in one of two ways, depending on the basic nature of the model. It has been included as a basic element in models such as the World Gas Trade Model (WGTM).[11] It also has been added to an expanded version of the Hydrocarbon Supply Model (HSM) that was used for the National Petroleum Council Natural Gas Study (1992).

Global trade models are based on a disaggregation of the world, in which countries or groups of countries are separated into consuming and producing regions. Each region has a stylized representation of supply and demand. Regions are connected via a transportation network, characterized by interregional transportation costs and flow constraints. LNG is incorporated into global trade models as possible gas trade between two noncontiguous countries. The model solves for the most efficient regional allocation of quantities and corresponding prices. The

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[11]The World Gas Trade Model (WGTM) basically is a global expansion of the NARG, using the Generalized Equilibrium Modeling System (GEMS). This model will not be described in detail because of the extreme similarity of the two models.

extensive scope of these models (and commonly encountered limitations of the necessary data) does not allow for detailed representations of gas supply or demand.

The incorporation of LNG trade into each model generally has occurred as an enhancement of established models. Both LNG imports and exports are included, with LNG exports from Alaska as an exogenous factor. LNG imports are represented as gas supply available to the appropriate U.S. regions according to a prespecified schedule reflecting industry announcements. The model solution includes an endogenous determination of flows through LNG facilities and new capacity in response to price.

The LNG algorithm in OGSM differs from the OGSM supply approaches for domestic and Canadian production. It utilizes supply curves for LNG imports, but it does not model explicitly the exploration and development process. These supply curves are based on the estimated cost of delivering LNG into the pipeline network in the United State and include all costs associated with production, liquefaction, shipping, and regasification. The supply curves mark the unit costs, which serve as economic thresholds that must be attained before investment in potential LNG projects will occur. Extensive operational assumptions were made on current import terminal capacity and the timing of planned capacity expansions.

### *Gas Trade with Mexico*

Gas trade between the United States and Mexico tended to be overlooked in earlier modeling efforts. This treatment (or lack thereof) seemed justified for a number of reasons. Except for a brief 5 year period in the early 1980s, neither gross nor net flows of gas between the United States and Mexico were significant. Additionally, reliable data regarding Mexican gas potential were not readily available.

A scenario basis was chosen to handle gas imports from Mexico because of uncertainty and the significant influence of noneconomic factors that affect Mexican gas trade with the United States. Many of the models described previously make use of such exogenous offline analyses to forecast certain variables. For example, DRI's offshore oil and gas production forecasts are handled offline and integrated later into their main forecasting model.

## Alaskan Oil and Gas Supplies

Alaska has a limited history as a source of significant volumes of crude oil and natural gas. Initial commercial flows of crude oil from the Alaskan North Slope began on June 17, 1977. Interest in analyzing the volumetric potential of Alaska as a source of oil or gas supplies arose after the late 1960s discovery of the Prudhoe Bay field, which is the largest in North America. During the years since the mid 1970s, there have been numerous special studies of either a one-time nature or limited in scope. An early study by Mortada (1976) projected expected oil production through 2002.[12] The results of this analysis were used in Congressional hearings regarding the construction and operation of the Trans-Alaska Pipeline System (TAPS). A Department of the Interior (DOI) study (1981) analyzed the supply potential of the National Petroleum Reserve - Alaska (NPRA). This work was used in the consideration of leasing the NPRA for exploration and development.

Generalized models that deal with both oil and gas potential for Alaska are not as common as those for the Lower 48 states. Most forecasting agencies, including the EIA, have not devoted a large amount of resources towards the development and maintenance of a detailed Alaskan oil and gas representation in their domestic production models. Generally, forecasting groups either adopted a projection from another agency, or utilized other

[12]Mortada International, *The Determination of Equitable Pricing Levels for North-Slope Alaskan Crude Oil*, (October 1976).

projections as the basis for selected *ad hoc* modifications as appropriate. The latter approach occurs in EIA's previous modeling work regarding Alaskan supply in PROLOG.

This seeming inattention to building an Alaska oil and gas supply model arose from the limited extent of the projection horizon that was needed until recently. Projections in EIA had been for periods of 10 to 15 years, and up to 20 years only recently. This period length limits the flexibility in Alaskan activities, where lags of 10 to 15 years affect the discovery and development process. Thus, the bulk of oil production for at least 15 years under virtually any scenario depends almost wholly on the recovery from currently known fields. Marketing of natural gas from the Alaskan North Slope is not expected prior to the beginning of the next decade at the earliest, because of the lack of facilities to move the gas to Lower 48 markets and the interest of the operators and the State of Alaska in using the natural gas to maximize recovery of oil from Prudhoe Bay.

The present methodology for the Alaska Oil and Gas Supply Submodule (AOGSS) differs from that of the Lower 48 States representation. A discovery process approach with ad hoc constraints was chosen for the AOGSS. This method was chosen because of the unique nature of industry operations in Alaska and the limited number of fields do not lend themselves readily to application of the Lower 48 approach.

The AOGSS is divided into three components: new field discoveries, development projects, and producing fields. A discounted cash flow method is used to determine the economic viability of each project at netback price. The netback price is determined as the market price less intervening transportation costs. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and development projects, and historical production patterns and announced plans for currently producing fields.

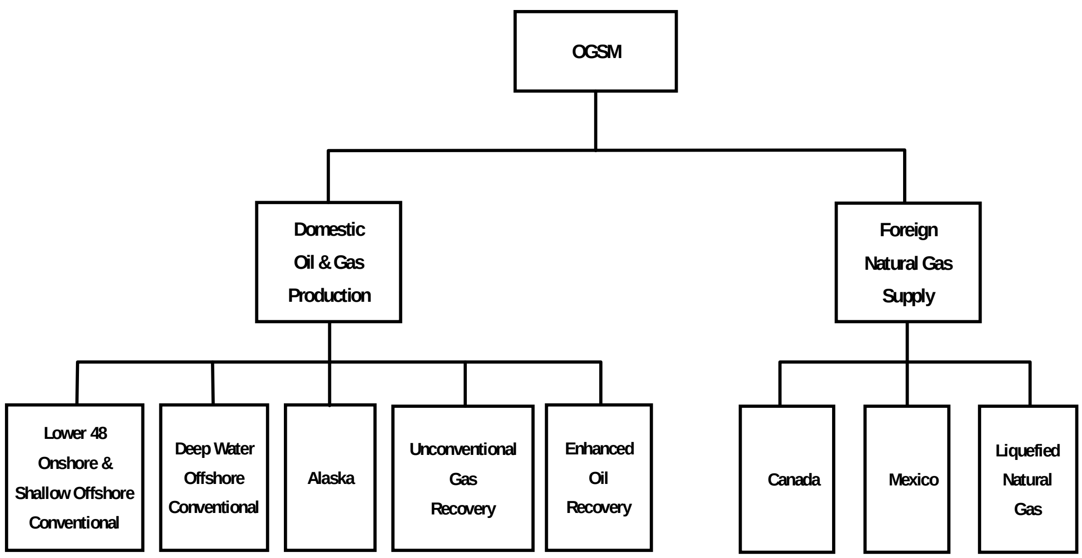
Oil and gas prices are the principal driving variables and are received from the Petroleum Market Module and the Natural Gas Transmission and Distribution Module respectively.

# 4. Model Structure

## Introduction

This chapter describes the Oil and Gas Supply Module (OGSM), which consists of a set of submodules (Figure 3) that perform supply analysis regarding 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 National Energy Modeling System (NEMS). The oil and gas supplies in each period are balanced against the regional derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the disjoint wellhead and enduse 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).

**Figure 3. Submodules within the Oil and Gas Supply Module**




The OGSM mirrors the activity of numerous 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 enhanced oil recovery (EOR), and unconventional gas recovery (UGR) from tight gas formations, Devonian/Antrim shale and coalbeds. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM represents foreign trade in natural gas as imports and exports by entry region of the United States. These foreign transactions may occur via either pipeline (Canada or Mexico), or via ships transported as liquefied natural gas (LNG).

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.

The OGSM includes an enhanced methodology for estimating short-term oil and gas supply functions. Short-term is defined as a one year period in the OGSM. This enhancement improves the procedure for equilibrating the natural gas and oil markets by allowing for the determination of regional market clearing prices for each fuel, as opposed to the previous modeling system that only equilibrates markets at a national market clearing price.

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 economically recoverable resource base[1] convert to proved reserves.[2] The previous model treated reserve additions primarily as a function of undifferentiated exploratory drilling. The relatively small amount of reserve additions from other sources was represented as coming from developmental drilling.

The OGSM distinguishes between drilling for new fields and that for additional deposits within old fields. 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 recent literature regarding resource recovery.[5]

The breadth of supply processes that are encompassed within OGSM results in methodological differences between the lower 48 methodology and that for Alaska oil and gas production and foreign gas trade. The present OGSM consequently comprises a set of three distinct approaches and corresponding submodules. The label OGSM as used in this report generally refers to the overall framework and the implementation of lower 48 oil and gas supply in both onshore and shallow offshore regions. The Deepwater Offshore Supply Submodule

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[1] *Economically recoverable resources* are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional technologies, under specified economic assumptions. Economically 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. Economically recoverable resources are a subset of *technically recoverable resources*, which are those volumes producible with current recovery technology and efficiency but without reference to economic viability.

[2] *Proved reserves* are the estimated quantities that analysis 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.

(DWOSS) models oil and gas production in the deep offshore Gulf of Mexico. 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.

Several changes were made to OGSM for the AEO98. Most significant is the debut of the Deepwater Offshore Supply Submodule (DWOSS). In previous AEOs, supply projections for this region were based on analyses of historical data that was often limited in scope due to the region's frontier status. The DWOSS has the potential to significantly improve EIA's ability to model activity in this region in that it takes advantage of the fact that the number of deepwater projects is relatively small by modeling activity at the project level. Another change for AEO98 is that regional exploration and development drilling levels are now forecasted directly rather than being derived indirectly from forecasted drilling expenditures and drilling costs as was done previously. With respect to costs, the impact of rig utilization on drilling costs is now incorporated in the drilling costs equations. While this enhancement added complexity to the model (for instance, the model now needs to forecast the stock of rigs), the net effect was a plus in that the earlier formulation probably overstated the impact of technology on drilling costs. One final change worth noting is the new option by which production out of existing reserves is modeled. Previously, the user was required to specify a target ratio of production to reserves. This is not required under the new option. Instead, the new option relies on an econometric analysis of the production to reserves ratio.

The following sections describe OGSM grouped into four conceptually distinct divisions. The first section describes most oil and gas supply in the lower 48 states, including onshore lower 48 conventional oil and gas supply, shallow offshore oil and gas supply, and Unconventional Gas Recovery. This is followed by the methodology of the Deep Water Offshore Supply Submodule, the Enhanced Oil Recovery 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 three 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) calculation, the determination of unit costs for delivered LNG, and the finding rate function.

# Lower 48 Onshore and Shallow Offshore Supply Submodule

## Introduction

This section describes the structure of the models that comprise the lower 48 onshore (excluding EOR) and the lower 48 shallow offshore 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.

The OGSM receives regional oil and gas prices from the PMM and NGTDM, respectively. Using these prices in conjunction with data on production profiles, co-product ratios, drilling costs, lease equipment costs, platform costs (for offshore only), operating costs, severance tax rates, ad valorem tax rates, royalty rates, state tax rates, federal tax rates, tax credits, depreciation schedules, and success rates, the discounted cash flow (DCF) algorithm calculates expected DCF values in each period associated with representative wells for each region, well type (exploratory, developmental), and fuel type (oil, shallow gas, deep gas, and unconventional gas).

Exploratory and development wells by fuel type and region are predicted as functions of the expected profitabilities 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 (determined in the NGTDM and the PMM) is subtracted to yield the end of year reserves for the current period. These reserves along with an estimate of the expected production to reserves ratio for the next period are passed to the NGTDM and the PMM for use in their short-run supply functions.

## 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; the probability of failure is given by one minus the success rate. 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[6] 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.

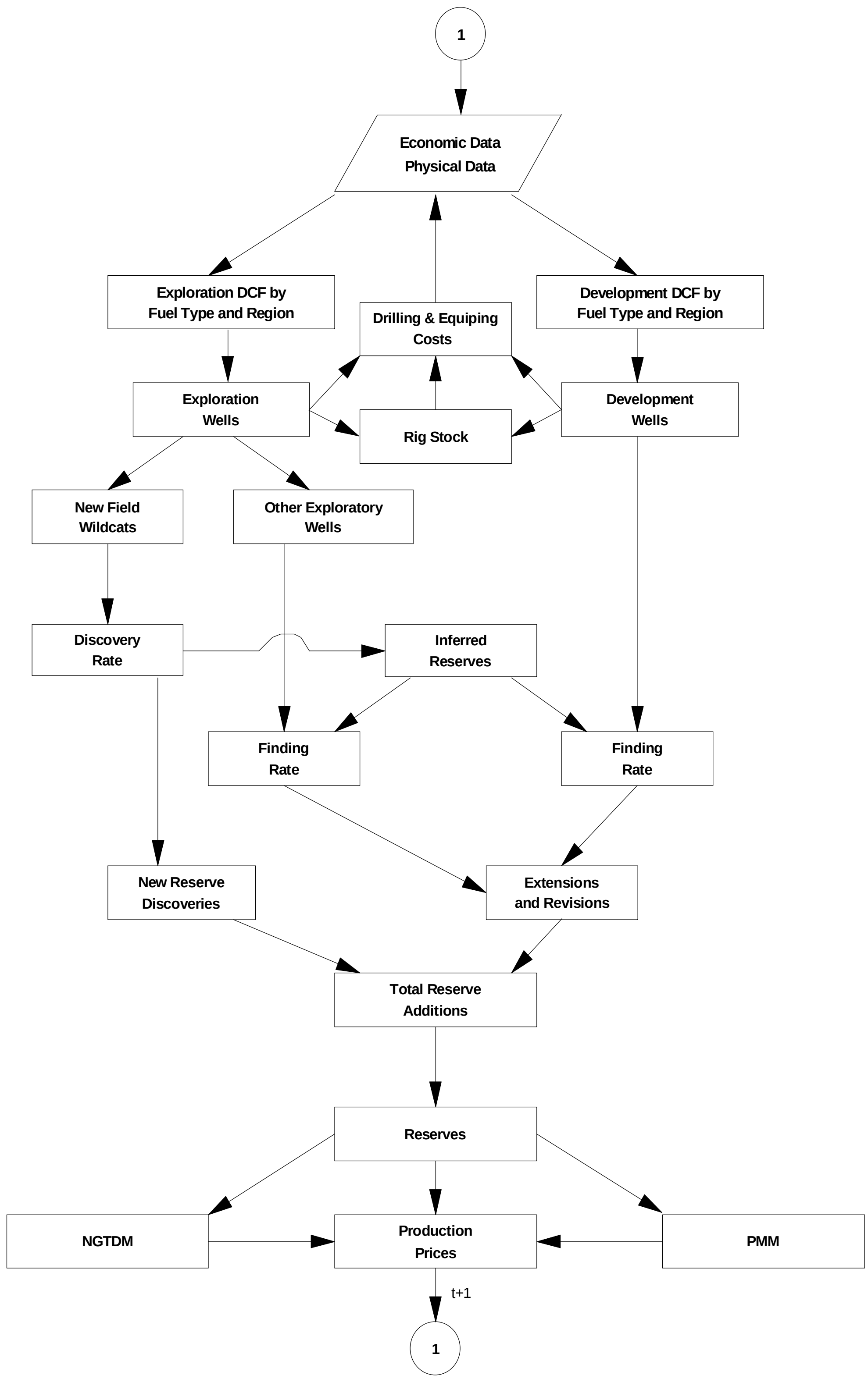
For each year of the project's expected lifetime, the net cash flow is calculated as:

$$\begin{aligned} NCFON_{i,r,k,s} = {} & (REV - ROY - PRODTAX - DRILLCOST - EQUIPCOST \\ & OPCOST - DRYCOST - STATETAX - FEDTAX)_{i,r,k,s}, \text{ for} \\ & r = 1 \text{ thru } 6,\ k = 1 \text{ thru } 6,\ s = t \text{ thru } t+L \end{aligned} \tag{1}$$

where,

[6]Equations (1) through (6) in this section and the following one describe the computation of the expected discounted cash flow estimate for a representative onshore exploratory or developmental well, denoted as $DCFON_{i,r,k,t}$ in equations (4) and (6). An equivalent set of calculations determine $DCFOFF_{i,r,k,t}$, the expected discounted cash flow estimate for a representative offshore exploratory or developmental well. In these equations, the suffix "ON" is replaced everywhere by "OFF," with all other particulars remaining the same. These alternate equations are not shown to avoid redundancy in the presentation.

**Figure 4. Flowchart for Lower 48 States Onshore and Offshore Oil and Gas Submodules**



| | | |
|---|---|---|
| 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 5 for OGSM region codes) |
| k | = | subscript indicating fuel type |
| s | = | subscript indicating year of project life |
| t | = | current year of forecast |
| L | = | expected project lifetime.[7] |

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 4-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:

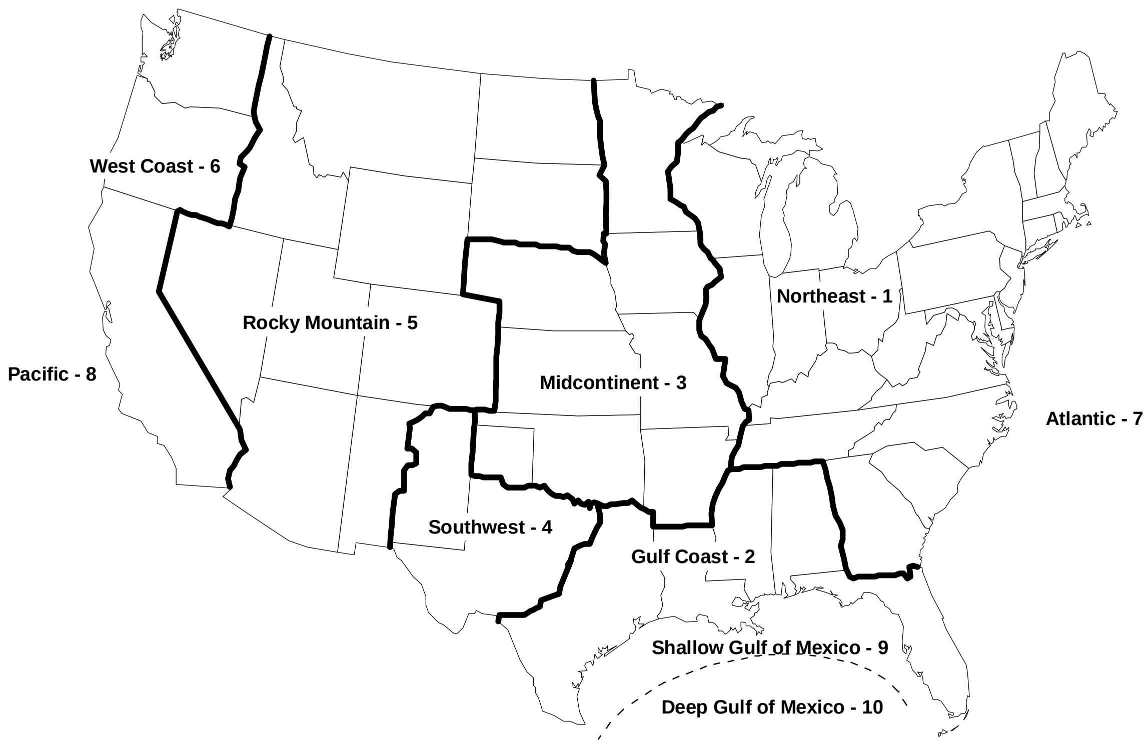
$$PROJDCFON_{i,r,k,t} = SUCDCFON_{i,r,k,t} + [(\frac{1}{SR_{i,r,k}}) - 1] * DRYDCFON_{i,r,k,t}, \quad \text{for } i = 2 \tag{2}$$

where,

| | | |
|---|---|---|
| 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). |

[7]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.

**Figure 5. Lower 48 Oil and Gas Supply Regions with Region Codes**




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

$$DCFON_{i,r,k,t} = SR_{i,r,k} * SUCDCFON_{i,r,k,t} + (1 - SR_{i,r,k}) * DRYDCFON_{i,r,k,t}, \text{ for } i = 2 \quad (3)$$

it is easily calculated as:

$$DCFON_{i,r,k,t} = PROJDCFON_{i,r,k,t} * SR_{i,r,k}, \quad \text{for } i = 2,\ r = 1 \text{ thru } 6,\ k = 1 \text{ thru } 6 \quad (4)$$

where,

DCFON = expected discounted cash flow for a representative onshore developmental well.

### *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:

$$PROJDCFON_{1,r,k,t} = SUCDCFON_{1,r,k,t} + m_k * \left[ SUCDCFON_{2,r,k,t} + \left( \left( \frac{1}{SR_{2,r,k}} \right) - 1 \right) * DRYDCFON_{2,r,k,t} \right] + \left( \left( \frac{1}{SR_{1,r,k}} \right) - 1 \right) * DRYDCFON_{1,r,k,t} \tag{5}$$

where,

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

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

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

$$DCFON_{1,r,k,t} = PROJDCFON_{1,r,k,t} * SR_{1,r,k} \tag{6}$$

### *Shallow Offshore Exploration and Development*

The calculations of the expected discounted cash flows for the lower 48 offshore regions (i.e., $DCFOFF_{i,r,k,t}$) are identical to those described for the lower 48 onshore. In addition, the economic assessment of an offshore development well matches that in the onshore. The sole difference relates to the specific characterization of an offshore exploration project, which is reflected in the input data for the offshore.

Specifically, an offshore exploration project consists of: (1) two successful new field wildcat wells drilled in the first year of the project from which there is no production; (2) three successful other exploratory wells that delineate the new field and begin producing in the second year of the project along with the requisite number of dry other exploratory wells; (3) eight successful developmental wells that are drilled and begin producing in the third year of the project along with the requisite number of dry developmental wells; and (4) one successful developmental well that is drilled and begins producing in each of the next seven years of the project along with the requisite number of dry holes.

### *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, since the OGSM forecasts an aggregate level of both exploratory and development wells for unconventional gas recovery rather than forecasting separately wells drilled for tight sands, devonian shale, and coalbed methane, an aggregate expected DCF for unconventional gas recovery is calculated for each onshore region except region 6. This aggregate expected DCF for unconventional gas recovery is calculated for each well class and region as a weighted average of the expected DCF's for each unconventional gas category. The weights are equal to the share of total unconventional gas wells in a particular unconventional gas category in the previous period. Specifically,

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_{k} WELLS_{i,r,k,t-1}, \quad \text{for } k = 4, 5, 6 \tag{7}$$

and

$$UGDCFON_{i,r,t} = \sum_{k=4} w_{i,r,k,t} DCFON_{i,r,k,t}, \quad \text{for } i = 1,2, \ r = 1,2,3,4,5 \tag{8}$$

where,

| | | |
|---|---|---|
| WELLS | = | wells drilled |
| UGDCFON | = | expected DCF for unconventional gas recovery. |

For some onshore well equations, a regional exploratory or development expected DCF is used as a proxy for expected profitability. These are calculated as weighted averages of the fuel specific expected DCF's in each region. The weights are equal to the share of total wells of type I drilled in region r of fuel type k in the previous period. Specifically,

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_{k} WELLS_{i,r,k,t-1}, \quad \text{for each } i, \ r, \ k \tag{9}$$

where,

| | | |
|---|---|---|
| WELLS | = | wells drilled. |

The expected DCF's are then derived using the following equation:

$$RDCFON_{i,r,t} = \sum_{k} w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i = 1, 2, \ r = \text{onshore regions}, \ k = 1 \text{ thru } 6 \tag{10}$$

where,

| | | |
|---|---|---|
| RDCFON | = | onshore regional expected discounted cash flow per well |

Finally, in several cases, the expected profitability of a representative onshore exploratory oil and/or shallow gas well is proxied by a combined oil/shallow gas exploratory expected DCF for the specific region, denoted by the variable name OSGDCFON. Analogous to the alternatives described above, this measure is calculated as a weighted average of the exploratory oil and shallow gas expected DCF's in the region. The weights are equal to the shares of the total number of oil and shallow gas exploratory wells drilled in the region in the previous period. Algebraically:

$$OSGDCFON_{i,r,t} = \sum_{k=1}^{2} w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i=1,\ r,\ k=1,2 \tag{11}$$

where:

$$w_{i,r,k,t} = WELLSON_{i,r,k,t-1} / \sum_{k=1}^{2} WELLSON_{i,r,k,t-1}, \quad \text{for } i=1,\ r,\ k=1,2 \tag{12}$$

### *Lower 48 Wells Forecasting Equations*

For each onshore Lower 48 region, the shallow Gulf offshore region, and the Pacific offshore 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. 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 and may incorporate dummy variables to capture the effects of structural changes.[8] For the Pacific offshore, only oil development wells are forecasted.

For unconventional gas recovery, wells for each unconventional gas type are determined by applying regional historical shares to total unconventional gas wells drilled for each onshore region. The specific forms of the equations used in forecasting wells are given in Appendix B. These equations can be expressed in the following generalized form.[9]

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUMXX_t \tag{13}$$

$$WELLSOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k} * DCFOFF_{i,r,k,t} + \alpha 2_{i,r,k} * DUMZZ_t \tag{14}$$

where,

| | | |
|---|---|---|
| WELLSON | = | lower 48 onshore wells drilled by class, region, and fuel type |
| WELLSOFF | = | lower 48 offshore 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 |
| DCFOFF | = | expected DCF for a representative offshore well of class I, in region r, for fuel type k, in year t |
| DUMXX | = | 1 if year $\geq$ 19XX<br>0 otherwise |
| DUMZZ | = | 1 if year $\geq$ 19ZZ |

[8] Some of these dummy variables are only applied to historical years and will appear in the estimation description in Appendix E but, because they are equal to zero in the projection period, will not appear in the mathematical description in Appendix B.

[9] For the shallow gas exploratory wells in onshore region 2 and for the oil and gas development wells in the offshore Gulf, the forecasting equations took the general exponential form given by:

$$WELLS = \exp(\beta_0 + \beta_1 * DCF + \beta_2 * DUMXX)$$

where exp represents the exponential function and the $\beta$'s are estimated parameters.

0 otherwise
m's, α"s = estimated parameters
i = well type
r = lower 48 regions
k = fuel type
t = year.

Other variables not defined above that appear in specific equations are defined in Appendix E. Additionally, a number of the forecasting equations include a correction for first order serial correlation. The general form is given below with the onshore notation used for exposition purposes only. The form for the offshore equations is identical.

$$\begin{aligned} WELLSON_{i,r,k,t} = \; & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUMXX_t + \rho_{i,r,k} * WE \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUMXX_{t-} \end{aligned} \tag{15}$$

where,

ρ = estimated serial correlation parameter.

## 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,

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 6 \tag{16}$$

$$SUCWELSOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{17}$$

where,

SUCWELSON = successful onshore lower 48 wells drilled
SUCWELSOFF = successful offshore lower 48 wells drilled
WELLSON = onshore lower 48 wells drilled
WELLSOFF = offshore lower 48 wells drilled
SR = drilling success rate
i = well type (1 = exploratory, 2 = development)
r = lower 48 regions, onshore and offshore
k = fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas, 5 = Devonian shale gas, 6 = coalbed methane)
t = year.

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

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t}, \text{ for } i = 1, 2, r = \text{onshore regions}, k = 1 \text{ thru } 6 \tag{18}$$

$$DRYWELOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} - SUCWELSOFF_{i,r,k,t}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{19}$$

where,

DRYWELON = number of dry wells drilled onshore

| | | |
|---|---|---|
| DRYWELOFF | = | number of dry wells drilled offshore |
| SUCWELSON | = | successful lower 48 onshore wells drilled by fuel type, region, and well type |
| SUCWELSOFF | = | successful lower 48 offshore wells drilled by fuel type, region, and well type |
| WELLSON | = | onshore lower 48 wells drilled by fuel type, region, and well type |
| WELLSOFF | = | offshore lower 48 wells drilled by fuel type, region, and well type |
| i | = | well type (1 = exploratory, 2 = development) |
| r | = | lower 48 regions, onshore and offshore |
| k | = | fuel type (1 = oil, 2 = shallow gas, 3 = deep gas, 4 = tight sands gas, 5 = Devonian shale gas, 6 = coalbed methane) |
| 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, total drilling is estimated as a function of price as generalized below:

$$ESTWELLS_t = \exp(b0) * \exp(b1 * \log(POIL_t) * \log(PGAS_t)) \qquad (20)$$

where,

| | | |
|---|---|---|
| ESTWELLS | = | estimated total onshore lower 48 wells drilled |
| POIL | = | average wellhead price of crude oil |
| PGAS | = | average wellhead price of natural gas |
| WELLSL48 | = | total onshore lower 48 wells drilled |
| b0, b1 | = | estimated parameters |
| t | = | year. |

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

$$RIGSL48_t = \exp(b0) * RIGSL48_{t-1}^{b1} * REVRIG_{t-1}^{b2} \qquad (21)$$

where,

| | | |
|---|---|---|
| RIGSL48 | = | onshore lower 48 rigs |
| REVRIG | = | total drilling expenditures per rig |
| b0, b1, b2 | = | estimated parameters |
| t | = | year. |

### *Drilling Costs*

**Onshore**

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

$$\text{DRILLCOST}_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * \text{ESTWELLS}_t^{b3_k} * \text{RIGSL48}_t^{b4_k} * \exp(b5 * \text{TIME}_t) \tag{22}$$

$$\text{DRYCOST}_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_{d,k}) * \exp(b2_{r,k}) * \text{ESTWELLS}_t^{b3_k} * \text{RIGSL48}_t^{b4_k} * \exp(b5 * \text{TIME}_t) \tag{23}$$

where,

| | | |
|---|---|---|
| DRILLCOST | = | drilling cost per well |
| DRYCOST | = | drilling cost per dry well |
| ESTWELLS | = | estimated total onshore lower 48 wells drilled |
| RIGSL48 | = | onshore lower 48 rigs |
| TIME | = | time trend - proxy for technology |
| r | = | OGSM lower 48 onshore region |
| k | = | fuel type (1 = oil, 2 = shallow gas, 3 = deep gas) |
| d | = | depth class |
| b0, b1, b2, b3, b4, b5 | = | estimated parameters |
| t | = | year. |

**Shallow Offshore**

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

$$\text{DRILLCOST}_k = \exp(\delta 0_k) * \text{GOMWELLS}_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * \text{RIGSOFF}_{t-2}^{\delta 3_k} * \exp(\delta 4_k * \text{TIME}_t) \tag{24}$$

$$\text{DRYCOST}_k = \exp(\delta 0_k) * \text{GOMWELLS}_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * \text{RIGSOFF}_{t-2}^{\delta 3_k} * \exp(\delta 4_k * \text{TIME}_t) \tag{25}$$

where,

| | | |
|---|---|---|
| DRILLCOST | = | drilling cost per successful well |
| DRYCOST | = | drilling cost per dry hole |
| GOMWELLS | = | total gulf of mexico offshore wells drilled |
| RIGSOFF | = | total offshore rigs |
| TIME | = | time trend - proxy for technology |
| d | = | depth per well |
| k | = | fuel type (1 = oil, 2 = gas) |
| δ0, δ1, δ2, δ3, δ4 | = | estimated parameters |
| t | = | year. |

In each period of the forecast, the total number of wells is determined by:

$$\text{GOMWELLS}_t = \exp(\alpha) * \exp(\beta * \log(\text{POIL}_t) * \log(\text{PGAS}_t)) \tag{26}$$

where,

| | | |
|---|---|---|
| POIL | = | average wellhead price of crude oil |
| PGAS | = | average wellhead price of natural gas |
| α, β, ρ | = | estimated parameters. |

In each period of the forecast, the total rigs available is determined by:

$$RIGSOFF_t = \exp(\alpha) * RIGSOFF_{t-1}^{\beta} * REVRIG_{t-2}^{\gamma} \tag{27}$$

where,

| | | |
|---|---|---|
| RIGSOFF | = | number of rigs available in year t |
| REVRIG | = | total drilling expenditures per rig |
| α, β, γ | = | estimated parameters |
| t | = | year. |

### *Lease Equipment Costs*

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

$$LEQC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * ESUCWELL_{k,t}^{b2_k} * \exp(b3_k * TIME_t) \tag{28}$$

where,

| | | |
|---|---|---|
| LEQC | = | oil and gas well lease equipment costs |
| DEPTH | = | average well depth |
| ESUCWELL | = | estimated lower 48 successful onshore wells (oil, gas) |
| TIME | = | time trend - proxy for technology |
| ϵ0, ϵ1, ϵ2 | = | estimated parameters |
| r | = | OGSM lower 48 onshore region |
| k | = | fuel type (1=oil, 2=shallow gas, 3=deep gas) |
| t | = | year. |

### *Operating Costs*

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

$$OPC_{r,k,t} = \exp(b0_{r,k}) * \exp(b1_k * DEPTH_{r,k,t}) * SUCWELL_{k,t-1}^{b2_k} * \exp(b3_k * TIME_t) \tag{29}$$

where,

| | | |
|---|---|---|
| OPC | = | oil and gas well operating costs |
| SUCWELL | = | lower 48 successful onshore wells (oil, gas) |
| DEPTH | = | average well depth |
| TIME | = | time trend - proxy for technology |
| b0, b1, b2, b3 | = | estimated parameters |
| r | = | OGSM lower 48 onshore region |
| k | = | fuel type (1=oil, 2=shallow gas, 3=deep gas) |
| t | = | year. |

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 E.

## Reserve Additions

The Reserve Additions algorithm calculates units of oil and gas added to the stocks proved and inferred reserves.[10] 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.

Discoveries of previously unknown fields per period are modeled as a function of the number of new field wildcats drilled per period. 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. Within the model, other exploratory drilling accounts for proved reserves added through new pools or extensions, and development drilling accounts for reserves added through revisions.

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.[11]

### *Functional Forms*

Oil or gas reserve additions from new field wildcats are a function of the cumulative number of successful new field wildcats drilled, the initial estimate of economically recoverable resources for the fuel, and the rate of technological change.[12]

Total successful exploratory wells are disaggregated into successful new field wildcats and other exploratory wells based on a historical ratio. 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.

The major inputs to the new field reserve addition equation are new field wildcats drilled and the resource base.

This approach relies on the finding rate equation:

$$FR1_{r,k,t} = FR1_{r,k,t-1} * (1 + \beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) \tag{30}$$

where,

| | | |
|---|---|---|
| FR1 | = | new field wildcats finding rate |
| SW1 | = | successful new field wildcats |

[10]An important advantage inherent in OGSM's design is its modularity. The present finding rate specification of OGSM was developed to meet the analytical requirements and schedule for NEMS. Modifications will be made to the present discovery process methodology and resource accounting in the future.

[11]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.*

[12]A more complete discussion of the finding rate equations and the enhancement to include technological change is available in Appendix 4-C of this report.

$\delta1$ = finding rate decline parameter
$\beta1$ = finding rate technology parameter
r = region
k = fuel type (oil or gas)
t = year.

Under the above specification, the yield from new fieldcat drilling in the absence of technological change declines exponentially as cumulative drilling increases. Specifically, in the absence of technological change, the finding rate at the end of period t is lower than the finding rate in period t-1 by $\delta1$, the decline rate, times the number of wells drilled in period t. Technological change expands the economically recoverable resource volume beyond the initial estimate. Within OGSM, this is represented in two ways. First, the increase in the resource base is presumed to increase the finding rate by $\beta$ percent. Under this approach, the finding rate in period t can be higher, lower, or equal to the finding rate in t-1 depending on the value of $\beta$, $\delta$, and the number of wells drilled in period t. The increase in the economically recoverable can also affect the decline paramater, $\delta1$. Accordingly, $\delta1$ is recalculated in each period using the following equation:

$$\delta1_{r,k,t} = \frac{FR1_{r,k,t-1} * (1+\beta1) - FRMIN1_{r,k}}{QTECH_{r,k,t} - CUMRES_{r,k,t-1}} \tag{31}$$

where,

FR1 = new field wildcats finding rate
FRMIN1 = minimum economic finding rate for new field wildcat wells
QTECH = undiscovered economically recoverable resource estimate adjusted for expansion due to technological change
CUMRES = cumulative proved and inferred reserve discoveries over the projection period (initial value = 0)
t = forecast year.

In the numerator, the minimum economic finding rate is set as a percentage of the initial finding rate. The percentage is constant over the forecast, but varies among fuels and regions. The denominator represents the *remaining* economically recoverable resource estimate in undiscovered fields, so the cumulative reserves found over time must be deducted. $\delta1$ is constrained not to fall below 0.

The above equations provide a rate at which undiscovered resources convert into proved and inferred reserves as a function of the number of new field wildcats drilled. 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 integrating the finding rate with respect to wells drilled each period.

$$\begin{aligned} \Delta R_{r,k,t} &= \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t}\, d(SW1) \\ &\phantom{=} \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t-1}(1+\beta1) * \exp(-\delta1_{r,k,t} * SW1_{r,k,t}) d(SW1) \end{aligned} \tag{32}$$

where,

X = reserves growth factor

$\Delta R$ = additions to proved reserves.

The terms in equation (28) are all constants in period t, except for the SW1. X is derived from historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta 1_{r,k,t}$ are calculated, prior to period t, based on lagged variables and fixed parameters as shown in equations (26) and (27).

Reserves move from the realm of inferred to proved with the drilling of other exploratory wells or developmental wells in much the same way as proved and inferred reserves are modeled as moving from the resource base as described above. The volumetric return to other exploratory wells and developmental wells is shown in the following equations:

$$FR2_{r,k,t} = FR2_{r,k,t-1} * (1+\beta 2) * \exp(-\delta 2_{r,k,t} * SW2_{r,k,t}) \tag{33}$$

where,

FR2 = other exploratory wells finding rate
SW2 = successful other exploratory wells
$\beta 2$ = technology parameter for FR2.

$$FR3_{r,k,t} = FR3_{r,k,t-1} * (1+\beta 3) * \exp(-\delta 3_{r,k,t} * SW3_{r,k,t}) \tag{34}$$

where,

FR3 = developmental wells finding rate
SW3 = successful development wells
$\beta 3$ = technology parameter for FR3.

The derivation of updated decline factors for the exponentially declining functions are shown in the following equations for other exploratory drilling and developmental drilling, respectively.

$$\delta 2_{r,k,t} = \left[ \frac{(FR2_{r,k,t-1}(1+\beta 2) - FRMIN2_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \tag{35}$$

$$\delta 3_{r,k,t} = \left[ \frac{(FR3_{r,k,t-1}(1+\beta 3) - FRMIN3_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1} (\frac{X-1}{X}) \int FR1_{r,k,t} d(SW1) - \sum_{T+1}^{t-1} [\int FR2_{r,k,t} d(SW2) + \int FR3_{r,k,t} d(SW3)]} \right] \tag{36}$$

where,

I = initial inferred reserves estimate
DECFAC = decline rate adjustment factor.
FRMIN2 = minimum economic finding rate for other exploratory wells
FRMIN3 = minimum economic finding rate for developmental wells

The conversion of inferred reserves into proved reserves occurs as both other exploratory wells and developmental wells exploit a single stock of inferred reserves. The specification of equations (50) and (51) has the characteristic that the entire stock of inferred reserves can be exhausted through either the other exploratory wells or developmental wells alone. This extreme result is unlikely given reasonable drilling levels in any one year. Nonetheless, the simultaneous extraction from inferred reserves by both drilling types could be expected to affect the productivity of each other. Specifically, the more one drilling type draws down the inferred reserve stock, there could be a corresponding acceleration in the productivity decline of the other type. This is because in a given year the same initial recoverable resource value (i.e., the denominator expression in the derivation of $\delta_2$ and $\delta_3$) is decremented by either type of drilling.

DECFAC is present in the computation of $\delta_2$ and $\delta_3$ to account for the simultaneous drawdown from inferred reserves by both other exploratory wells and developmental wells. DECFAC is a user-specified parameter that should be greater than or equal to 1.0. Values greater than 1.0 accelerate the productivity decline in finding rates. The parameter values for the *Annual Energy Outlook 1998* are 1.0 for both the onshore and the offshore. Subsequent to recent resource updates, the relative drawdown of inferred reserves in any year was judged insufficient to significantly impact the resource accounting in either case.

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

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t} d(SW3) \tag{37}$$

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

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{38}$$

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 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. The user has an option of three different approaches to determine the PR ratio.

**Option 1**

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

$$PR_t = \frac{Q_t}{R_{t-1}} \tag{39}$$

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.

$PR_t$ represents the rate of extraction from all wells drilled up to year t (through year t-1). To calculate the expected rate of extraction in year (t+1), the model combines production in year t with the reserve additions and the expected extraction rate from new wells drilled in year t. The calculation is given by:

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{40}$$

where,

$PR_{t+1}$ = expected production to reserves ratio for year (t+1)
PRNEW = long-term expected production to reserves ratio for all wells drilled in forecast
$R_t$ = end of year reserves for year t or equivalently, beginning of year reserves for year (t+1).

The numerator, representing expected total production for year t+1, comprises the sum of two components. The first represents production from proved reserves as of the beginning of year t. This production is the expected production in year t, $R_{t-1}$*$PR_t$, adjusted by 1-$PR_t$ to reflect the normal decline from year t to t+1. The second represents production from reserves discovered in year t. No production in year t+1 is assumed from reserves discovered in year t+1.

Under this option, $PR_t$ is constrained not to vary from $PR_{t-1}$ by more than 5 percent. It is also constrained not to exceed 30 percent.

The values for $R_t$ and $PR_{t+1}$ are passed to the NGTDM and the PMM for use in their market equilibration algorithms which solve for equilibrium production and prices for year (t+1) of the forecast using the following short-term supply function:

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \tag{41}$$

where,

$R_t$ = end of year reserves in period t
$PR_t$ = extraction rate in period t
$\beta$ = estimated short run price elasticity of supply
$\Delta P_{t+1}$ = $(P_{t+1}-P_t)/P_t$, 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. The OGSM passes estimates of β to the NGTDM and PMM that can be used in solving for the market equilibria. Documentation of the equations used to estimate β is provided in Appendix E, pp. E-29 through E-37.

**Option 2**

Options 2 is an econometric alternative to the approach presented under option 1. The determinants of the production to reserves ratio in a given region include the regional wellhead price and unobserved regional specific effects such as geology. The relationship between the PR ratio and price as well as other factors is not linear given that ratio is bounded between zero and one. For this reason, a logistic transformation of the PR ratio was the dependent variable in the regression equation. Given this approach, the estimated PR equation for region r in year t is

$$PR_{r,k,t} = \frac{X_{r,k,t}}{1 + X_{r,k,t}} \tag{42}$$

where $X_{r,k,t}$ is defined as follows.

***Natural Gas***

$$X_{r,k,t} = \exp((1-\rho gas)*cgas_r) * \exp(h*CARRIAGE_t) * \exp(-\rho gas*h*CARRIAGE_{t-1})* \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * PGAS_{r,t}^{\alpha} * PGAS_{r,t-1}^{-\rho gas*\alpha} \tag{43}$$

where,

| | | |
|---|---|---|
| CARRIAGE | = | share of pipeline deliveries transported for others |
| PR | = | production to reserves ratio |
| PGAS | = | average wellhead price of natural gas |
| r | = | region |
| k | = | fuel type (1=oil, 2=gas) |
| t | = | year |
| cgas, h, α, ρgas | = | estimated parameters. |

The variable CARRIAGE is equal to one over the forecast period. It was included in the equation to account for the transition to open access over the sample period.

***Crude Oil***

$$X_{r,k,t} = \exp((1-\rho oil)*coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \exp(\beta*POIL_{r,t}) * \exp(-\rho oil*\beta*POIL_{r,t-1}) \tag{44}$$

where,

| | | |
|---|---|---|
| PR | = | production to reserves ratio |
| POIL | = | average wellhead price of crude oil |
| r | = | region |
| t | = | year |
| coil, β, ρoil | = | estimated parameters. |

The PR ratio is multiplied by the beginning-of-year crude oil reserves to get production by region. This volume is then passed to the PMM for use in their market equilibration.

**Option 3**

Options 3 is another econometric alternative to the approach presented under option 1. The determinants of the production to reserves ratio include the same variables as in option 2 as well as a ratio of reserve additions relative to reserves. Specifically, the estimated PR equation for region r in year t is

$$PR_{r,k,t} = \frac{X^{\circ}_{r,k,t}}{1 + X^{\circ}_{r,k,t}} \tag{45}$$

where $X^{\circ}_{r,k,t}$ is defined as follows.

***Natural Gas***

$$\begin{aligned} X^{\circ}_{r,k,t} = {} & \exp((1-\rho gas)*cgas_r) * \exp(h*CARRIAGE_t) * \exp(-\rho gas*h*CARRIAGE_{t-1})* \\ & \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * \exp(fgas_r*RA_{r,k,t-1}) * \exp(-\rho gas*fgas_r*RA_{r,k,t-2}) \end{aligned} \tag{46}$$

where,

| | | |
|---|---|---|
| CARRIAGE | = | share of pipeline deliveries transported for others (reflects the industry's transition to open access) |
| PR | = | production to reserves ratio |
| RA | = | reserve additions to reserves ratio |
| r | = | region |
| k | = | fuel type (1=oil, 2=gas) |
| t | = | year |
| cgas, h, fgas, ρgas | = | estimated parameters. |

The NGTDM uses the following function to determine the wellhead prices given the production to reserves ratios.

$$PGAS_{r,t} = PGAS^{\rho}_{r,t-1} * \left(\frac{PR_{r,t}}{1-PR_{r,t}}\right)^{\frac{1}{B}} * \left(\frac{PR_{r,t-1}}{1-PR_{r,t-1}}\right)^{-\frac{\rho}{B}} * Z^{\circ\,\frac{1}{B}}_{r,t} \tag{47}$$

where,

$$\begin{aligned} Z^{\circ}_{r,t} = {} & \exp((\rho gas-1)*cgas(r)) * \exp(-h*CARRIAGE(t)) * \exp(\rho gas*h*CARRIAGE(t-1)) * \\ & \exp(-fgas_r*RA_{r,k,t-1}) * \exp(\rho gas*fgas_r*RA_{r,k,t-2}) \end{aligned} \tag{48}$$

***Crude Oil***

$$X^{\circ}_{r,k,t} = \exp((1-\rho oil) * coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \exp(\beta * POIL_{r,t}) * \exp(-\rho oil * \beta * POIL_{r,t-1}) * \exp(foil_r * RA_{r,k,t-1}) * \exp(-\rho oil * foil_r * RA_{r,k,t-2}) \tag{49}$$

where,

| | | |
|---|---|---|
| PR | = | production to reserves ratio |
| POIL | = | average wellhead price of crude oil |
| RA | = | reserve additions to reserves ratio |
| r | = | region |
| t | = | year |
| coil, β, ρoil | = | estimated parameters. |

The PR ratio is multiplied by the beginning-of-year crude oil reserves to get production by region. This volume is then passed to the PMM for use in their market equilibration.

## Associated Dissolved Gas

Associated dissolved (AD) gas production is estimated as a function of crude oil production. The basic form of the equation is given as:

$$ADGAS_{r,t} = e^{\ln(\alpha)_r} * OILPROD_{r,t}^{\beta} \tag{50}$$

where,

| | | |
|---|---|---|
| ADGAS | = | associated dissolved gas production |
| OILPROD | = | crude oil production |
| r | = | OGSM region |
| t | = | year |
| α,β | = | estimated parameters. |

This simple regression function is used in the estimation of AD gas production in onshore regions 1 through 4. A time dummy is introduced in onshore regions 5 and 6 and offshore regions of California and the Gulf of Mexico to represent loosening of restrictions on capacity and changes in regulation. Specifically,

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r * DUM86_t} \tag{51}$$

where,

| | | |
|---|---|---|
| DUM86 | = | dummy variable (1 if t>1985, otherwise 0) |
| α0,α1,β0,β1 | = | estimated parameters. |

# Deep Water Offshore Supply Submodule

This section describes the basic structure of the Deep Water Offshore Supply Submodule (DWOSS). The DWOSS is designed to project oil and gas production from the deep water region of the Gulf of Mexico. This section provides an overview of the basic approach. A more detailed description of the methodology is presented in Appendix 4D as well as a discussion of the characterization of the undiscovered resource base and the rationale behind the various technology options for deep water exploration, development and production practices incorporated in the DWOSS.

The DWOSS was developed offline from the OGSM. A methodology was developed within OGSM to enable it to readily import and manipulate the DWOSS output, which consists essentially of detailed price/supply tables disaggregated by Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil, natural gas). At the most fundamental level, therefore, it is useful to identify the two structural components that make up the DWOSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

***Exogenous Component.*** A methodology for developing deepwater offshore undiscovered resource price/supply curves, employing a rigorous field-based discounted cash-flow (DCF) approach,[15] was constructed exogenously from OGSM. This offline portion of the model utilizes key field properties data, algorithms to determine key technology components, and algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable reserves for the different fields are aggregated by planning region and by resource type to generate resource-specific price-supply curves. In addition to the overall supply price and reserves, cost components for exploration, development drilling, production platform, and operating expenses, as well as exploratory and development well requirements, are also carried over to the endogenous component.

***Endogenous Component.*** After the exogenous price/supply curves have been developed, they are transmitted to and manipulated by an endogenous program within OGSM. The endogenous program contains the methodology for determining the development and production schedule of the deepwater offshore Gulf of Mexico OCS oil and gas resources from the price/supply curves. The endogenous portion of the model also includes the capability to estimate the impact of penetration of advanced technology into exploration, drilling, platform, and operating costs as well as growth of reserves.

# Enhanced Oil Recovery Supply Submodule

This section describes the structure of the Enhanced Oil Recovery Supply Submodule (EORSS). The EORSS is designed to project regional oil production in the onshore lower 48 states extracted by use of tertiary recovery techniques. This section provides an overview of the basic approach including a discussion of the procedure for projecting production from base year reserves and the methodology for development and subsequent production from previously unproven reserves.

## Introduction

All submodules in the OGSM share similar basic attributes, but the EOR representation differs in the particulars. The EORSS uses a modified form of the previously described methodology, which is used for conventional oil supply and all natural gas recovery types in the lower 48 states. This section presents a discussion of the general differences in the EOR methodology.

The basic supply process for both EOR and the other sources of crude oil and natural gas consists of essentially the same stages. The physical stages of the supply process involve the conversion of unproven resources into proved reserves, and then the proved reserves are extracted as flows of production. The significant differences between the methodology of the EORSS and the other submodules of OGSM concern the conversion of unproven resources to proved reserves, the extraction of proved reserves for production, and the determination of supply activities.

The EORSS uses discovery factors that convert a specified fraction of unproven resources into proved reserves. These factors depend on the expected profitability of EOR investment opportunities. This approach is a substitute for the approach used elsewhere in OGSM in which the transfer of resource stocks from unproven to proved status is accomplished by use of finding rate functions that relate reserve additions to cumulative drilling levels. Greater expected financial returns motivate the conversion of larger fractions of the resource base into proved reserves. This is consistent with the principle that funds are directed toward projects with relatively higher returns.

An explicit determination of expenditures for supply activities does not occur within the EORSS as it does elsewhere in the OGSM. Given the role of the discovery factors in the supply process, the implicit working assumption is that EOR investment opportunities with positive expected profit will attract sufficient financial development capital. The exploitation of economic EOR resources without an explicit budget constraint is consistent with the view that EOR investment does not compete directly with other oil and gas opportunities. This assumption is considered acceptable because EOR extraction is unlike the other oil and gas production processes, and its product differs sufficiently from the less heavy oil most often yielded by conventional projects.

## EOR Production from Proved Reserves

Input: reserves differentiated by unit operating costs (constitutes price-supply table)[13]

For every year of the forecast horizon, the remaining proved reserves in the price-supply table that continue to be economic are identified. Proved reserves that have unit operating costs that exceed the current net price do not contribute to current production. The net price is the current price less royalty payments and severance taxes, which are unavoidable costs per unit. Thus, the net price measures the unit revenue that accrues to the producing firms. Production from a given stock of proved reserves is determined by the application of an assumed production-to-reserves ratio (Figure 6).

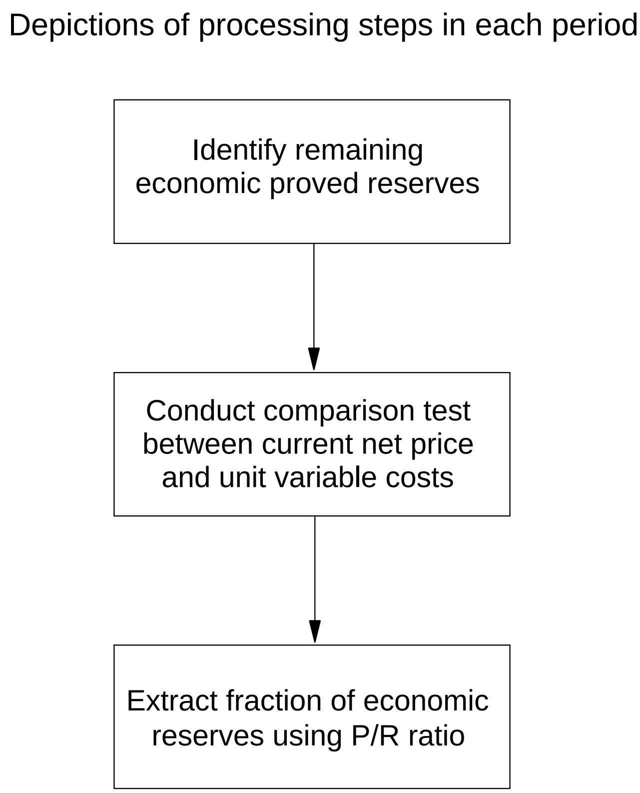
## New EOR Projects

Input: reserves differentiated by unit operating costs (constitutes price-supply table)

Use current year price to identify the economic portion of remaining unproven inferred reserves (Figure 7). Economic projects are transferred to undeveloped inferred reserves status. The economic portion of undeveloped inferred reserves become proved reserves based on net difference between price and unit cost. The rate of

[13]The EOR price-supply tables used in this submodule are of critical importance to any outlook. The estimates provided in these tables are generated from an elaborate preprocessor routine, that performs economic evaluations intended to be consistent with the detailed geological, engineering, and economic information maintained in the Tertiary Oil Recovery Information System (TORIS). TORIS is a large analysis system maintained by the Bartlesville Project Office of the DOE Office of Fossil Energy (OFE). TORIS originally was developed for use in the analysis sponsored by the National Petroleum Council in their comprehensive 1984 study on EOR. A complete description of the EORSS preprocessor and its relationship to the EORSS will be published in the spring of 1996 as a special appendix to this document.

**Figure 6. Procedure for EOR Production from Proved Reserves**

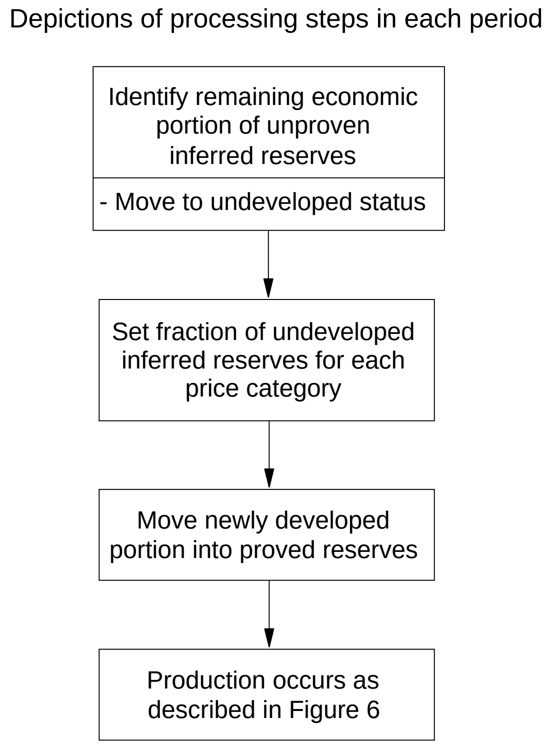



conversion is a fraction determined as the inverse of the expected number of years for development (see table below). The new additions to this stock are economic given the current price as indicated by theeconomic test in the previous step. Subeconomic portions of the preexisting undeveloped stock are not developed, because the development fractions (i.e., the inverse of the expected years for development) are zero if unit costs exceed the net current price

**Expected Development Schedule for Economic Undeveloped Inferred Reserves EOR Projects**

| Difference in Price over Unit Cost | Expected Years for Development |
|---|---|
| $0-1.00 | 40 |
| $1.01-2.00 | 36 |
| $2.01-3.00 | 32 |
| $3.01-4.00 | 28 |
| $4.01-5.00 | 24 |
| > $5.00 | 20 |

**Figure 7. Development of New EOR Projects**




The conversion of the appropriate volume of undeveloped reserves into proved reserves is followed by the extraction of a fraction of proved reserves as production. Production from a given stock of proved reserves is determined by use of the assumed production-to-reserves ratio.

## Cogeneration

Cogeneration of electricity by EOR projects is determined by a streamlined algorithm. This method assigns a level of new cogeneration capacity based on the EOR expansion from new projects. Electricity from existing capacity occurs according to assumed utilization factors.

# 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.) 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 8).Transportation costs are used in conjunction with the relevant market price of oil or 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 each project at the netback price. Alaskan oil and gas supplies are modeled on the basis of discrete projects, in contrast to the Onshore Lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multi-year projects, as well as the discovery of a new field is dependent on its 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
- Operating costs (including production facilities and general and administrative costs).

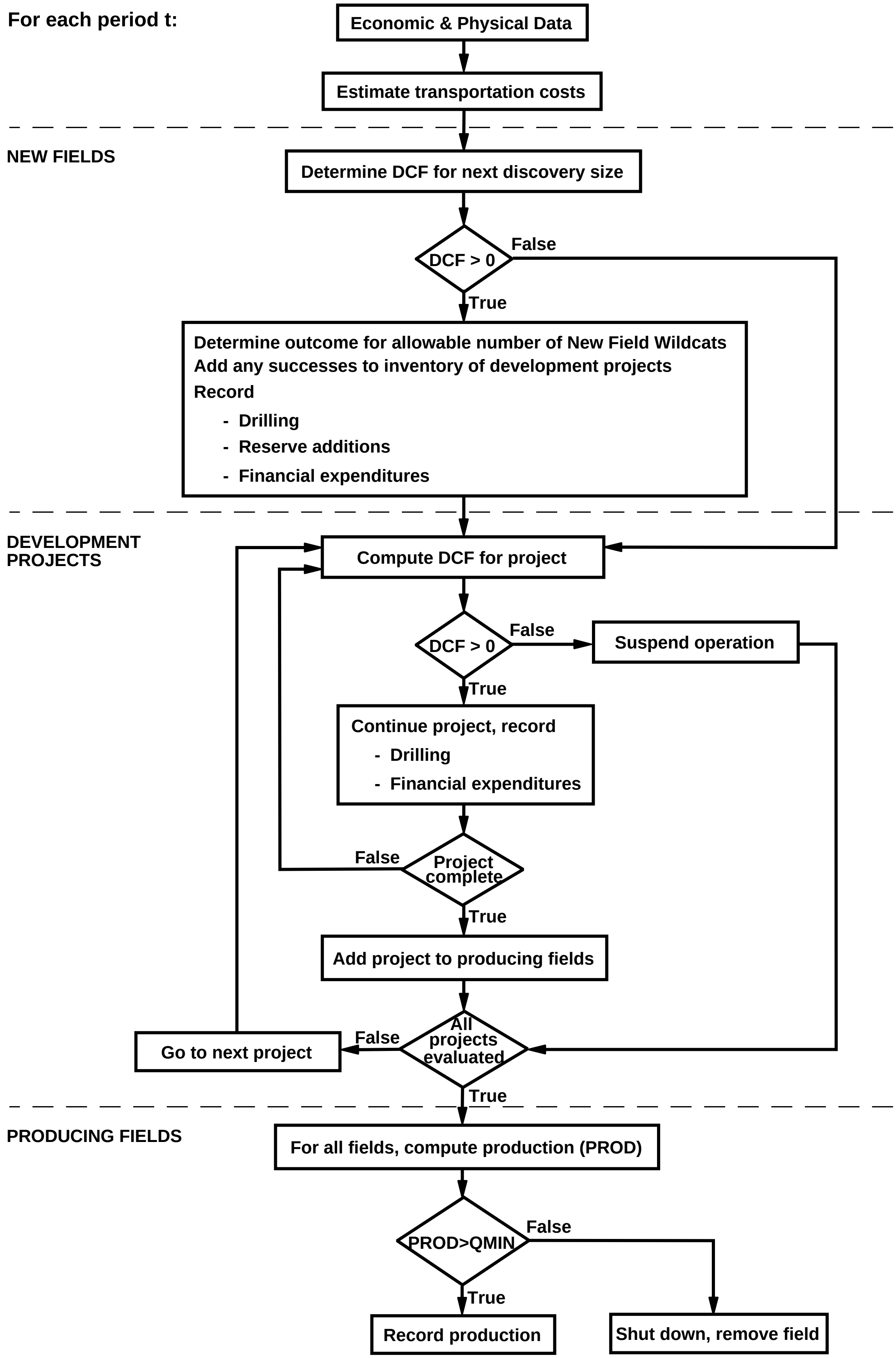
All costs in the model incorporate the estimated impact of environmental compliance. Whenever environmental regulations preclude a supply activity outright, that provision is reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations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

Each cost function includes a variable that reflects the cost savings associated with technological improvements. Such declines would be relative to what costs would otherwise be. Technological improvements lower average costs of the affected phase of activity. As such, the lower costs reflect changes in the cost of either the supply activity or environmental compliance. The value of this variable is a user option in the model. The equations used to estimate the costs are similar to those used for the lower 48 but include costs of elements that are particular to Alaska. For example, lease equipment includes gravel pads.

### *Drilling Costs*

Drilling costs represent the expenditures for drilling successful wells or 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.

**Figure 8. Flowchart for the Alaska Oil and Gas Supply Module**



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

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1)**(t-T_b) \tag{52}$$

where,

| | | |
|---|---|---|
| I | = | well class(exploratory=1, developmental=2) |
| r | = | region |
| k | = | fuel type (oil=1, gas=2) |
| t | = | forecast year |
| DRILLCOST | = | drilling costs |
| $T_b$ | = | base year of the forecast |
| TECH1 | = | annual decline in drilling costs due to improved technology. |

The above function specifies that drilling costs decline at the annual rate TECH1. Observe that drilling costs are not modeled as a function of the activity level as they are in the Onshore Lower 48 methodology. The justification for this is the relative constancy of activity in Alaska as well as the specialized nature of drilling inputs in Alaska.

### *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, and production related infrastructure such as gravel pads. Producing equipment costs include tubing and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells. The lease equipment cost estimate for a new oil or gas well is given by:

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{53}$$

where,

| | | |
|---|---|---|
| r | = | region |
| k | = | fuel type (oil=1, gas=2) |
| t | = | forecast year |
| EQUIP | = | lease equipment costs |
| $T_b$ | = | base year of the forecast |
| TECH2 | = | annual decline in lease equipment costs due to improved technology. |

### *Operating Costs*

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

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{54}$$

where,

| | | |
|---|---|---|
| r | = | region |
| k | = | fuel type (oil=1, gas=2) |
| t | = | forecast year |
| OPCOST | = | operating cost |
| $T_b$ | = | base year of the forecast |
| TECH3 | = | annual decline in operating costs due to improved technology. |

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

### *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 are expensed. The specific split between expensing and amortization is determined on the basis of the data.
- 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.

### *Tariff Routine*

In general, tariffs are designed to enable carriers to recover operating and capital costs for a given after-tax rate of return. The Trans Alaska Pipeline System (TAPS) tariff is determined by dividing the total revenue requirement for a year by the projected throughput for that year. The total revenue requirement is composed of eight elements as defined in the Settlement Agreement dated June 28, 1985 between the State of Alaska and ARCO Pipe Line Company, BP Pipelines Inc., Exxon Pipeline Company, Mobil Alaska Pipeline Company, and Union Alaska Pipeline Company. The determination of costs conforms to the specification as provided in the Settlement Agreement.

$$TRR_t = OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t$$
$$NONTRANSREV_t + CARRYOVER_t \tag{55}$$

where,

| | | |
|---|---|---|
| TRR | = | total revenue requirement |
| OPERCOST | = | total operating costs (fixed and variable) |
| DRR | = | dismantling, removal, and restoration allowance |
| TOTDEP | = | total depreciation (original and new property) |
| MARGIN | = | total after-tax margin (original and new property) |
| DEFRETREC | = | total recovery of deferred return (original and new property) |
| TXALLW | = | income tax allowance |
| NONTRANSREV | = | non-transportation revenues |
| CARRYOVER | = | net carryover. |

Four of the elements are associated with the recovery of a TAPS carrier's costs: (1) operating expenses, (2) dismantling, removal, and restoration (DR&R) allowance, (3) depreciation, and (4) income tax allowance. Two elements, after-tax margin and recovery of deferred return, provide for a return on unrecovered capital and an incentive to continue to operate the pipeline. The last two components, non-transportation revenues and net carryover are adjustment items.

**Operating Costs.** Operating costs include both the fixed and variable operating costs. The fixed portion is based on an assumed cost of $325 million (in 1991 dollars). If the expected throughput for the year is greater than 1.4 million barrels per day, the variable cost is $0.28 per barrel in 1991 dollars; otherwise, the variable cost is $0.24 per barrel in 1991 dollars.[14] These assumed costs exclude any incurred or expected DR&R expenses, any depreciation or amortization of capitalized cost, and any settlements with shippers for lost or undelivered oil due to normal operations during transportation.

**DR&R Allowance.** The annual DR&R allowance to be included in the revenue requirement calculation for years 1984 through 2011 is given in Exhibit E: DR&R Allowance Schedule of the Settlement Agreement.

**Depreciation.** Total depreciation is the sum of depreciation from original property and depreciation from new property as given by

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{56}$$

where,

| | | |
|---|---|---|
| TOTDEP | = | total depreciation |
| DEP | = | depreciation factor |
| DEPPROP | = | total (original and new) depreciable property in service |
| ADDS | = | additions to both original and new property in service |
| PROCEEDS | = | proceeds from both original and new depreciable property in service. |

**After-Tax Margin.** The after-tax margin is designed to provide the TAPS carrier with an after-tax real return on capital. This margin has two components: (1) the product of the allowance per barrel and the projected throughput and (2) the allowed rate of return on the rate base associated with new property in service. The allowance per barrel is set at $0.35 in 1983 dollars and the allowed rate of return at 6.4 percent.

[14]The variable cost was converted from 1983 dollars as specified in the Settlement Agreement to 1991 dollars.

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \quad (57)$$

where,

| | | |
|---|---|---|
| MARGIN | = | total after-tax margin |
| ALLOW | = | allowance per barrel |
| THRUPUT | = | projected net deliveries |
| $DEPPROP_{NEW}$ | = | new depreciable property in service |
| $DEFRET_{NEW}$ | = | new deferred return |
| $DEFTAX_{NEW}$ | = | new deferred tax. |

**Recovery of Deferred Return.** Deferred returns represent amounts which could be rightfully collected and turned over to the owners but, for tariff profile purposes, are collected at a later date. For example, Construction Work in Progress (CWIP) is not added in the company's rate base until the end of the construction period. As a result, it is not included in the return on capital and not recovered in current rates. Instead, an Allowance for Funds Used During Construction (AFUDC) is added to the book value of the construction. This deferred return is then recovered through depreciation of the pipeline's cost over its economic life. The recovery of this deferred return has two components, the conventional AFUDC and the inflation portion of the return on rate base. The calculation of the recovery of deferred returns is given by

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \quad (58)$$

where,

| | | |
|---|---|---|
| DEFRETREC | = | total recovery of deferred return (original and new property) |
| DEP | = | depreciation factor |
| DEFRET | = | total deferred return (original and new property) |
| INFLADJ | = | inflation adjustment (original and new property) |
| AFUDC | = | allowance for funds used during construction. |

**Income Tax Allowance.** The income tax allowance is equal to the income tax allowance factor multiplied by the sum of the after-tax margin and recovery of deferred return. The income tax allowance factor is the amount of tax allowance necessary to provided a dollar of after tax income at the composite Federal and State tax rates, adjusted for the deductibility of State income tax in Federal tax calculations.

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \quad (59)$$

where,

| | | |
|---|---|---|
| TXALLW | = | income tax allowance |
| TXRATE | = | income tax allowance factor |
| MARGIN | = | total after-tax margin |
| DEFRETREC | = | total recovery of deferred return. |

**Non-transportation Revenues.** A TAPS owner receives revenues from the use of carrier property in addition to the tariff revenue. These incidental revenues include payments received directly or indirectly from penalties paid by shippers who were delinquent in taking delivery of crude oil at Valdez. By subtracting these revenues from the total revenue requirement, the economic benefit to these non-transportation revenues is passed on to other shippers through the lower tariff for TAPS transportation.

**Net Carryover.** The net carryover reflects any difference between the expected revenues calculated by this tariff routine and revenues actually received.

## Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil and gas projects.[15] 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 of either oil or gas reflect delivery costs to an oil import facility or the citygate for natural gas. Transportation costs for oil include both pipeline and tanker shipment costs, and natural gas transportation costs are pipeline costs (tariffs). Transportation costs are specified for each field, although groups of fields may be subject to uniform transportation costs for that region. This cost directly affects the expected revenues from the production of a field as follows:[16]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_{f,t}) \tag{60}$$

where,

| | | |
|---:|---|---|
| f | = | field |
| t | = | year |
| REV | = | expected revenues |
| Q | = | expected production volumes |
| MP | = | market price in the lower 48 states |
| TRANS | = | transportation cost. |

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

$$DCF_{f,t} = (PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP - PVOPCOST - PVPRODTAX - PVSIT - PVFIT - PVWPT)_{f,t} \tag{61}$$

here,

| | | |
|---:|---|---|
| PVREV | = | present value of expected revenues |
| PVROY | = | present value of expected royalty payments |
| PVDRILLCOST | = | present value of all exploratory and developmental drilling expenditures |
| PVEQUIP | = | present value of expected lease equipment costs |
| TRANSCAP | = | cost of incremental transportation capacity |
| PVOPCOST | = | present value of operating costs |
| PVPRODTAX | = | present value of expected production taxes (ad valorem and severance taxes) |
| PVSIT | = | present value of expected state corporate income taxes |
| PVFIT | = | present value of expected federal corporate income taxes |

[15]See Appendix 4.A at the end of this chapter for a detailed discussion of the DCF methodology.

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

PVWPT = present value of expected windfall profits tax[17]

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

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \qquad (62)$$

here,

PVEXPCOST = present value exploratory drilling costs
PVDEVCOST = present value developmental drilling costs
PVEQUIP = present value lease equipment costs
TRANSCAP = cost of incremental transportation capacity

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

$$PROF_{f,t} = DCF_{f,t} \;/\; COST_{f,t} \qquad (63)$$

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 requires needed information, which can be determined endogenously or supplied at the option of the user. The procedure requires data regarding:

- technically recoverable oil and gas resource estimates by region
- distribution of technically recoverable field sizes[18] within each region
- the maximum number of new field wildcat wells drilled in any year
- new field wildcat success rate
- any restrictions on the timing of drilling.

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
- a schedule for the discovery sequence.

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[17]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.

[18]"Size" of a field is measured by the volume of recoverable oil or gas.

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 was gathered from the U.S. Geological Survey work for the national resource assessment.[19] 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 conform 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 8 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. This refinement is implemented by declaring a start date for possible exploration. For example, 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.

Every year, the DCF is calculated for each 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.[20] The specific assumptions used in this work are as follows:

- a two to four year build-up period from initial production to peak rate,
- peak rate sustained for three to eight years, and
- production rates decline by 12 or 15 percent after peak rate is no longer maintained.

The pace of development and 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.)

[19] *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States -- A Part of the Nation's Energy Endowment*, USGS (1989).

[20] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge*, EIA (1987) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

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.

### Producing Fields

Oil and natural gas production from fields producing as of the base year (including 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.

Natural gas production from the North Slope for sale to end-use markets is dependent on the construction of a major transportation facility to move natural gas to lower 48 markets.[21] In addition, the reinjection 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 delay to maximize oil recovery, but it does not require any further modifications from the basic procedure.[22]

## Foreign Natural Gas Supply Submodule

This chapter describes the proposed 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.[23] Gas is traded with Canada and Mexico via pipelines. Gas trade with other, nonadjacent, countries is in the form of liquefied natural gas (LNG) and involves liquefaction, transportation by tanker and subsequent regasification. To date, the United States has imported LNG almost exclusively from Algeria.

A detailed representation of Canadian gas trade has been developed. Since forecasts of fixed volumes are not adequate for the purposes of equilibrating supply and demand, the submodule provides the Natural Gas Transmission and Distribution Module (NGTDM) with supply functions of Canadian gas at the U.S./Canadian border points. 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, transportation, and regasification. Projected pipeline imports from Canada and LNG imports are subject to user assumptions regarding the timing and size of available import capacity. Natural gas exports, via pipeline or as LNG, are included in the National Energy Modeling System (NEMS) as a set of exogenous assumptions. This section presents descriptions of the separate methodological approaches for Canadian, Mexican, and LNG natural gas trade.

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[21]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction.

[22]The currently proposed version of AOGSS does not include plans for 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.

[23]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.

## Canadian Gas Trade

This submodule determines net Canadian natural gas supplies over a range of gas prices to the United States at the six border crossing locations identified in Figure 9. The initial step in this procedure produces projections of regional Canadian drilling activity and supply. Canadian demand is subtracted from supply to determine gas available for export. Gas supply is allocated to regional Canadian/U.S border crossing points using an allocation algorithm that accounts for the associated pipeline capacities and the price responsiveness of supplies at the border points. The determination of the import volumes themselves occurs in the equilibration process of the NGTDM.

The approach taken to determine Canadian gas supply differs from that used in the domestic submodules of the OGSM. Drilling activity is determined using an econometric model. Drilling activity, measured as the number of successful wells drilled, is estimated directly as a function of expected profitability rather than being derived from a process of estimating and allocating drilling expenditures. Successful wells are disaggregated by two fuel types: oil and gas. No distinction is made between exploration and development. Production from three Canadian regions is estimated -- the Western Canadian Sedimentary Basin (WCSB) (Alberta, British Columbia, and Saskatchewan), the Northern Frontier (Arctic Islands and Mackenzie Delta), and Eastern Canada. Drilling activity for the WCSB is determined using an econometric model. Finding rate equations are used to determine reserve additions; a reserves accounting procedure yields reserve estimates; and an estimated extraction rate determines production potential for the WCSB. Production from the Northern Frontier and Eastern Canada regions, for which there are very limited data, is determined exogenously from resource supply curves that relate resource availability to price. Annual production from these regions is combined with WCSB production, yielding total Canadian domestic production. Total Canadian supply includes natural gas received from the United States.

Forecasts of Canadian gas demand are based on estimates made by the Canadian National Energy Board. Western Canadian gas demand is subtracted from total Canadian supply to determine available export supply. The general methodology employed for estimating Canadian gas trade is depicted in Figure 10.

### *Western Canadian Sedimentary Basin*

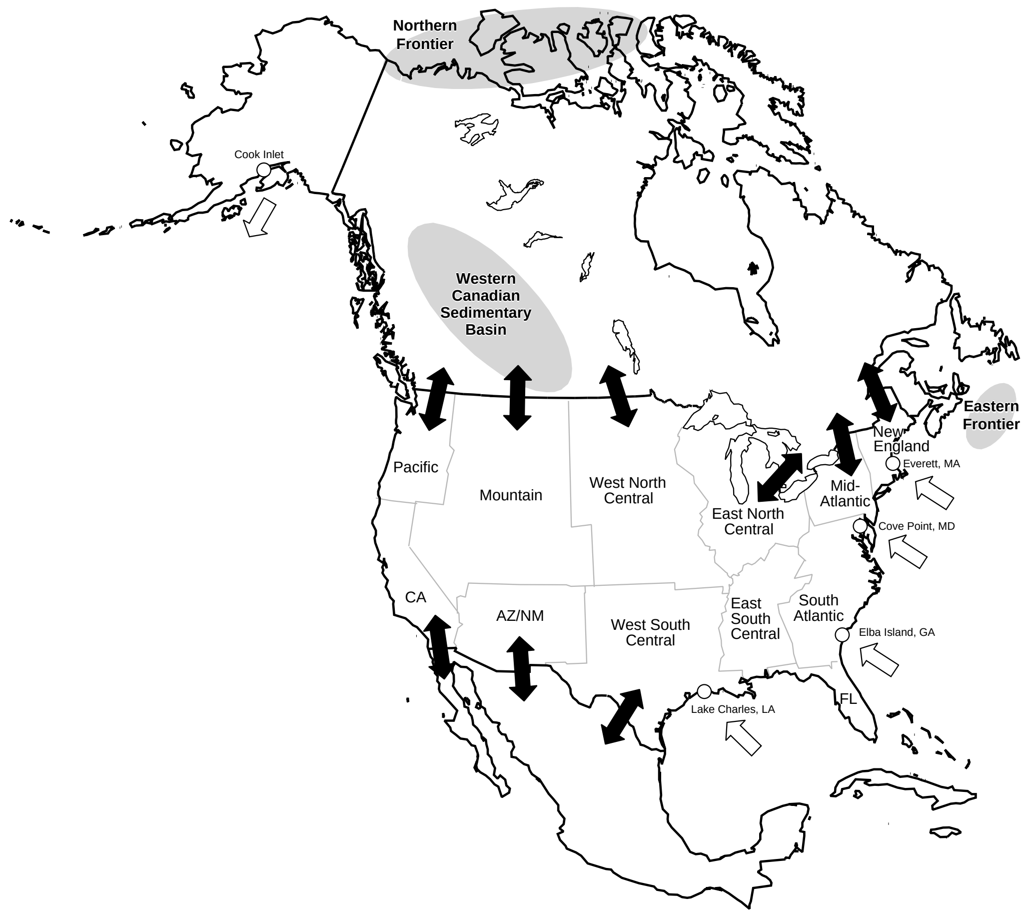
#### Calculation of Discounted Cash Flows

Expected discounted cash flows (DCF) associated with drilling representative oil and gas wells in the WCSB are calculated for each year t.[24] The DCF reflects expected revenues, less expected costs and taxes, all in present value terms. Expected revenue is based on expected production, over the life of the well, and expected prices. Expected production over the life of a representative well is based on the well's first year of production and the associated decline rate, by fuel type.

The world oil price and regional gas prices at the U.S./Canadian border for year t are received from the Petroleum Marketing Module (PMM) and the NGTDM respectively. An average Canadian wellhead gas price is determined as the weighted average of border prices less the markups from the field to the border crossing points. The weights are based on the flows of gas from the field to each border crossing point in the prior period. The Canadian wellhead prices for oil and gas, together with the expectations assumed, generate future price streams on which expected revenues are based. The subject of price expectations is presented in Appendix 4-A.

[24]See Appendix 4-A at the end of this chapter for a detailed discussion of the basic DCF methodology. The tax provisions described in this appendix are based on U.S. tax laws. The applicable provisions of Canadian tax law have been incorporated into the implemented DCF routine in the FNGSS.

**Figure 9. Foreign Natural Gas Trade via Pipeline**




Drilling, lease equipment, and operating costs per well for year t are received from the cost routines described below. The drilling and lease equipment costs per well constitute the initial capital costs and are assumed to be incurred entirely in year t.[25] Operating costs are incurred over the life of the well beginning with a half year of operation (assuming uniform occurrence of initial production for each new well throughout the year). The estimate of operating costs per well in year t yields the future stream of expected operating costs per well.

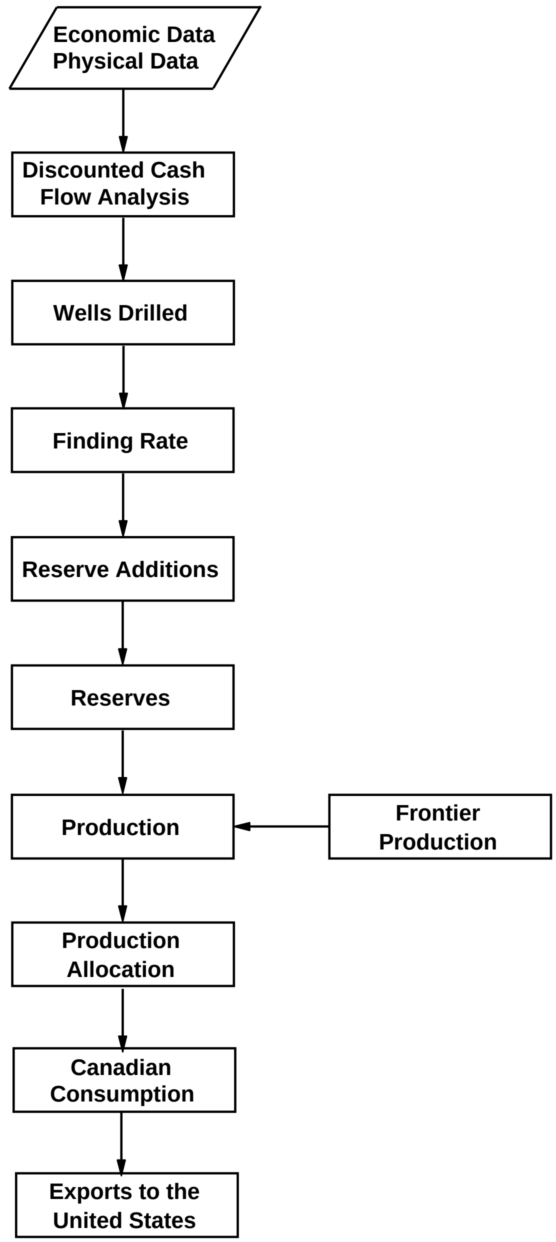
### Calculation of Costs

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

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

[25]Western Canadian Sedimentary Basin oil and gas prospects will be modeled as single year investments.

**Figure 10. A General Outline of the Canadian Algorithm of the FNGSS**



Relevant cost functions include TECH factors that proportionately adjust costs to reflect an annual decline due to technological improvements over time measured from the base year of the model. Such declines would be relative to what costs would otherwise be. TECH is a user specific input in the model with a prespecified default value. Enhancements to this approach is an area for consideration in later data and model development.

**Drilling Costs.** Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through to the "Christmas tree" installation. The "Christmas tree" refers to 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, direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Lease equipment required for production is included as a separate cost component, and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in the WCSB in year t is given by:

$$DRILLCOST_{k,t} = DRILLCOST_{k,t-1} * (1 - TECH1) \tag{64}$$

where,

| | | |
|---:|---|---|
| t | = | forecast year |
| k | = | fuel type (1 for oil, 2 for gas) |
| DRILLCOST | = | drilling costs, in Canadian dollars, of a successful oil or gas well |
| TECH1 | = | assumed annual decline in costs due to improved technology. |

The costs of drilling a dry hole are formulated in a like fashion:

$$DRYCOST_{t} = DRYCOST_{t-1} * (1 - TECH1) \tag{65}$$

where,

| | | |
|---:|---|---|
| t | = | forecast year |
| DRYCOST | = | drilling costs for a dry well in Canadian dollars |
| TECH1 | = | assumed annual decline in costs due to improved technology. |

**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 lease equipment cost estimate for a new oil or gas well is given by:

$$LEQUIPCOST_{k,t} = LEQUIPCOST_{k,t-1} * (1 - TECH2) \tag{66}$$

where,

| | | |
|---:|---|---|
| t | = | forecast year |
| k | = | fuel type (1 for oil, 2 for gas) |

| | | |
|---|---|---|
| LEQUIPCOST | = | lease equipment costs in Canadian dollars |
| TECH2 | = | assumed annual decline in lease equipment costs due to improved technology. |

**Operating Costs.** Operating cost data, which are input on a per well basis, 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, are also included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The cost of operating a well is given by:

$$OPCOST_{k,t} = OPCOST_{k,t-1} * (1 - TECH3) \tag{67}$$

where,

| | | |
|---|---|---|
| t | = | forecast year |
| k | = | fuel type (1 for oil, 2 for gas) |
| OPCOST | = | operating cost in Canadian dollars |
| TECH3 | = | assumed annual decline in operating costs due to improved technology. |

Drilling costs, lease equipment costs, and operating costs are integral components of the discounted cash flow analysis.

**Treatment of Costs in the Model for Tax Purposes.** The applicable provisions of Canadian tax law for oil and gas producers[26] have been incorporated into the discounted cash flow (DCF) analysis. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts.

**Discounted Cash Flow Analysis**

For each year t, the discounted cash flow for a successful well of fuel type k is calculated as the present value of revenues less the present value to costs and taxes. That is,

$$\begin{aligned} SUCDCF_{k,t} = (&PVREV - PVROY - DRILLCOST - LEQUIPCOST - PVOPCOST \\ &- PVPROVTAX - PVFEDTAX)_{k,t} \end{aligned} \tag{68}$$

where,

| | | |
|---|---|---|
| t | = | forecast year |
| k | = | fuel type (1 for oil, 2 for gas) |
| $SUCDCF_{k,t}$ | = | discounted cash flow for a successful well |
| PVREV | = | present value of expected revenues including the expected revenues from the sale of the co-product fuel |
| PVROY | = | present value of expected royalty payments |
| DRILLCOST | = | drilling cost in year t |

[26]Applicable provisions include such factors as determination and depreciation. The identification of relevant provisions and their representation with the DCF methodology will occur as part of a research effort that is not yet complete.

| | | |
|---|---|---|
| LEQUIPCOST | = | lease equipment costs in year t |
| PVOPCOST | = | present value of expected operating cost |
| PVPROVTAX | = | present value of expected income taxes to Canadian Provinces |
| PVFEDTAX | = | present value of expected federal corporate income taxes. |

The associated DCF for an unsuccessful well in year t is equal to:

$$DRYDCF_t = -(1 - FEDTXR) * (1 - PROVTXR) * DRYCOST_t \tag{69}$$

where,

| | | |
|---|---|---|
| DRYDCF | = | discounted cash flow for a dry well |
| FEDTXR | = | Canadian corporate tax rate |
| PROVTXR | = | weighted average provincial corporate tax rate |
| DRYCOST | = | dry hole costs. |

The expected DCF from drilling a representative prospect of fuel type k is a weighted sum of the representative DCF's of a successful and unsuccessful well, where the weights are the respective probabilities. In other words,

$$DCF_{k,t} = SR * SUCDCF_{k,t} + (1 - SR) * DRYDCF_t \tag{70}$$

where,

| | | |
|---|---|---|
| SR | = | success rate. |

This expression accounts for the expected discounted cash flow from a representative oil (gas) well, and incorporates expected revenues, expected costs (capital and operating), expected taxes, and the risk associated with drilling an oil (gas) well.

**Wells Determination: Econometric model**

The total number of successful wells drilled by fuel type in each year t is forecasted econometrically using the representative DCF's for each fuel type. Specifically,

$$\begin{aligned} WELLS_{k,t} = \; & \beta0_k + \beta1_k * DCF_{k,t} + \beta2_k * DUM83_t + \rho_k * WELLS_{k,t-1} - \rho_k * \\ & \beta0_k - \rho_k * \beta1_k * DCF_{k,t-1} - \rho_k * \beta2_k * DUM83_{t-1} , \\ & \text{for } k = \text{oil, gas} \end{aligned} \tag{71}$$

where,

| | | |
|---|---|---|
| $WELLS_{k,t}$ | = | number of successful wells of fuel type k (both exploration and development) drilled in time period t, |
| $DCF_{k,t}$ | = | expected discounted cash flow from drilling a representative prospect of fuel type k in time period t |
| DUM83 | = | dummy variable equal to 1 after 1982 |
| $\beta_o ,\beta_1, \beta_2$ | = | econometrically estimated parameters. |

**Reserve Additions**

The Reserve Additions algorithm calculates units of oil and gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of oil or gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which oil and gas become 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.

Oil and gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to wells or feet drilled in such a way that the rate of reserve additions declines as more wells are drilled. 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.

**Functional Forms.** The proposed model adopts the basic structure of the previous EIA Canadian supply model to determine Canadian reserve additions. Specifically, Canadian oil or gas reserve additions are a function of the cumulative number of successful wells drilled, the estimated economically recoverable resource base for the fuel, and the rate of technological change.

The finding rate equation for each fuel type is defined by:

$$FR_{k,t} = FR_{k,t-1} * \exp(-\delta_{k,t} * SUCWELLS_{k,t}) * (1 + FRTECH_k) \tag{72}$$

where,

| | | |
|---|---|---|
| $k$ | = | fuel type (1 for oil, 2 for gas) |
| $FR$ | = | finding rate |
| $SUCWELLS_{k,t}$ | = | successful wells of type k drilled in time period t |
| $\delta$ | = | finding rate decline parameter ($\delta$>0) |
| $FRTECH_k$ | = | finding rate technology factor. |

In this specification, the yield from successful drilling begins at the initial finding rate for each period, $FR_{k,t-1}$, and declines exponentially as drilling continues, but technological progress can reduce or even reverse this decline. This form is consistent with the methodology presented in Appendix 4C. The decline parameter, $\delta$, is estimable from the finding rate equation, given an estimate for ultimate recovery. A smaller estimate for the economically recoverable resource base would result in a more rapid decrease in productivity for the same level of cumulative drilling:  a larger value of $\delta$.

$$\delta_{k,t} = \frac{FR_{k,t-1} - FRMIN_k}{Q_k * (1.0 + TECH)^{t-T} - CUMRES_{k,t-1}} \tag{73}$$

where,

| | | |
|---|---|---|
| $t$ | = | forecast year |
| $k$ | = | fuel type (1 for oil, 2 for gas) |
| $FR$ | = | finding rate (millions of barrels in the case of oil, billion of cubic feet in the case of gas) |

| | | |
|---:|---|---|
| FRMIN | = | minimum economic finding rate |
| Q | = | economically recoverable resource estimate |
| TECH | = | technology factor |
| T | = | base year of the forecast |
| CUMRES | = | cumulative reserve discoveries over the projection period (initial value = 0). |

The denominator is the *remaining* economically recoverable resource estimate in a given period, so the cumulative reserves found over time must be deducted.

The minimum economic finding rate, FRMIN, is incorporated into equation (80) so that the cumulative reserve discoveries match the *economically* recoverable resource estimate when the yield from wells drilled falls to the economic minimum. Equation (80) also incorporates the benefits of technological change. Technological change is expected to improve the productivity of drilling by increasing the physical returns per drilling unit from what it otherwise would have been. Technological change is introduced through modifications of the initial economically recoverable resource estimate, thus affecting the value of the finding rate decline parameter, δ. It reflects the assumptions that technological change occurs over time and its effect is realized in the expansion of the resource estimate, thus lessening the decline rate of productivity and resulting in higher yields to drilling, relative to what they otherwise would have been. The growing recoverable volume necessitates recomputing δ in each period.

Total reserve additions in period t is given by:

$$RA_{k,t} = \int_{WELLS_{k,t-1}}^{WELLS_{k,t}} FR_{k,t} \ d(WELLS) \tag{74}$$

Finally, total end-of-year proved reserves for each period equals proved reserves from the previous period plus new reserve additions less production.

$$R_{k,t} = R_{k,t-1} + RA_{k,t} - Q_{k,t} \tag{75}$$

where,

| | | |
|---:|---|---|
| t | = | forecast year |
| k | = | fuel type (1 for oil, 2 for gas) |
| R | = | end-of-year reserves |
| Q | = | production |
| RA | = | reserve additions. |

(All volumes in millions of barrels or billions of cubic feet.)

### 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.

Canadian gas production in year t is given by:

$$Q_{gas,t} = R_{gas,t-1} * \Omega_{gas,t} * (1 + \beta_{gas} * \frac{\Delta P_{gas,t}}{P_{gas,t-1}}) \tag{76}$$

where,

$R_{gas,t-1}$ = end-of-year gas reserves in period t-1
$\Omega_{gas,t}$ = gas extraction rate in period t-1 (measured as the production to reserves ratio at the end of period t-1)
$P_{Gas,t}$ = gas netback price at the wellhead in period t
$\beta$ = estimated short run price elasticity of extraction
$\Delta P_{gas,t}$ = $(P_{gas,t}-P_{gas,t-1})$, the change in price from t-1 to t.

The proposed production equation relies on price induced variation in the extraction rate to determine short run supplies. The producible stock of reserves equals reserves at the end of the previous period. The extraction rate for the current period, $\Omega_{gas,t}$, is assumed as the approximate extraction rate for the current period under normal operating conditions. The product of $R_{gas,t-1}$ and $\Omega_{gas,t}$ is the expected, or normal, operating level of production for period t.

### *Supplies from the Northern Canadian Frontier and Eastern Canada*

Frontier production in FNGSS was to be determined as a sequence of predetermined estimates drawn from analysis of other analysis groups, such as the National Energy Board (NEB) of Canada[27] and the National Petroleum Council (NPC). The NEB work published in June 1991 indicates that the economics of frontier gas recovery and transportation prevent the occurrence of frontier flows until at least 2004. Subsequent communication with NEB staff indicate that their reassessment of frontier potential would delay frontier development until after 2010. Similarly, NPC analysis[28] showed that northern frontier gas would not be developed until after 2010 under most scenarios. Eastern Canada gas would occur only at the end of this period.

The present implementation of OGSM reflects the assumption that neither the northern nor eastern frontier Canadian gas sources will be developed until after 2010. This assumption appears reasonable in light of the results that other productive areas show sufficient productive potential to meet expected internal Canadian as well as U.S. demands.

### *Allocation of Natural Gas Production to Canada and the Canadian/U.S. Border*

Canadian natural gas production for export to the United States is estimated in several stages. First, an initial estimate of the wellhead price ($P_{gas,t}$) is used to determine aggregate Canadian gas production at the wellhead and aggregate Canadian demand. Total gas production available for export is estimated as,

$$Q_{ex,t} = Q_{gas,t} - D_{gas,t} \tag{77}$$

where,

$Q_{ex,t}$ = Canadian gas available for export
$Q_{gas,t}$ = Canadian gas production

[27] See, for example, *Supply and Demand: 1990-2010*, June 1991.

[28] *The Potential for Natural Gas in the United States*, December 1992.

$$D_{gas,t} \quad = \quad \text{Canadian gas consumption.}^{29}$$

The second stage of the procedure determines the allocation of the gas available for export among the six Canadian/U.S. border points. This aspect of the methodology is intrinsic to the U.S. market equilibration that occurs in the NGTDM. 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 noneconomic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is so great that not only is the magnitude of flow for any future year in doubt, but also the direction of flow. Reasonable scenarios have been developed and defended in which Mexico may be either a net importer or exporter of hundreds of billions of cubic feet of gas by 2010.[30]

The vast uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States suggest that these flows should be handled on a scenario basis. A method to handle user-specified path of future Mexican imports and exports has been incorporated into FNGSS. This outlook has been developed from an assessment of current and expected industry and market circumstances as indicated in industry announcements, or articles or reports in relevant publications. The outlook, regardless of its source, is fixed, and so it will not be price responsive.

## Liquefied Natural Gas

Liquefaction is a process whereby natural gas is converted into a liquid that can be shipped to distant markets that otherwise are inaccessible. Prospects for expanded imports of LNG into the United States are beginning to improve in spite of difficulties affecting the industry until recent years. Various factors contributed to the recent reemergence of LNG as an economically viable source of energy, including contracts with pricing and delivery flexibility, a growing preference toward natural gas due to the lesser environmental consequences for burning it versus other fossil fuels, and diversification and security of energy supply. The outlook for LNG imports also depends on customers' perceptions regarding supply reliability and price uncertainty.

### Determining U.S. Imports and Exports of LNG

Supply costs are input to the FNGSS. These supply, or delivery, costs of LNG measure all costs including regasification; that is, gas made ready for delivery into a pipeline. These values serve as economic thresholds that must be achieved before investment in the potential LNG projects occurs.

Imported LNG costs do not compete with the wellhead price of domestically produced gas; rather, these costs compete with the purchase price of gas prevailing in the vicinity of the import terminal. This is a significant element in evaluating the competitiveness of LNG supplies, since LNG terminals vary greatly in their proximity

[29] Consumption will be determined endogenously from demand functions, depending on availability of appropriate functional forms and parameter estimates from external sources, such as the Canadian National Energy Board. If these analytical elements are not available, Canadian consumption will be an exogenous input based on published outlooks from other agencies.

[30] For example, the National Petroleum Council study, *The Potential for Natural Gas in the United States*, December 1992.

to domestic producing areas. Terminals closer to major consuming markets have an inherent economic advantage over distant competing producing areas because of the lower transportation costs incurred.

In addition to the cost estimates, however, certain operational assumptions are required to complete the picture. Dominant factors affecting the outlook are: expected use of existing capacity, expansion at sites with existing facilities, and construction at additional locations. The FNGSS requires specification of a combination of factors: available gasification capacity, scheduled use of existing capacity, schedules for and lags between constructing and opening a facility, expected utilization rates, and worldwide liquefaction capacity. The current version of the FNGSS implicitly assumes that tanker capacity becomes available as needed to meet the transportation requirements.

A key assumption for any LNG outlook from FNGSS is that all major operational or institutional difficulties have been incorporated into the recognized allowable schedule for capacity operation and expansion. No other difficulties arise that are not resolved expeditiously.

## LNG Imports from Existing Capacity

There are four existing LNG terminal facilities in the United States, one each at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. The latter two terminals are currently idle (Figure 9).

Given the rather low variable costs (generally under $1.00 for liquefaction, tanker transportation, and regasification, but not including production), one can argue that the import volumes for these facilities have not been, and are not expected to be, determined on the basis of full cost recovery. The schedule for reopening these facilities are drawn from the announced plans for each import terminal, and modifications can be readily introduced at the user's request.

## LNG Imports from Capacity Expansion

Capacity expansion refers to additional capacity at the four sites that have capacity at present. The presence of a facility may be judged as reliable evidence that the local community has demonstrated tolerance for the facility and associated operations. The continuation of such tolerance is accepted as a working assumption.

The costs of capacity expansion are assumed to be consistent with those for new construction. Required operational assumptions include the lag in capacity expansion and the buildup period for full utilization of the incremental capacity. The difference in timing between the attainment of prices adequate to initiate capacity expansion and the initial operation of that expanded capacity is assumed to be one year. Given a required construction period likely exceeding one year, this assumption is consistent with some degree of anticipation of the growth in prices by the operators of the facility.

## New Construction

Increases in LNG deliveries beyond expanded capacity at existing sites require capacity expansion at sites other than those where facilities are currently located. New capacity construction requires a set of working assumptions that are either user specified or default parameters. Major operational assumptions include:

- Selected start dates before which construction of LNG terminals on new sites would not be allowed

- Design capacity and utilization rates for the newly constructed capacity

- Regional locations for new construction sites[31]
- Price increments that would bring forth additional LNG import capacity.

[31]The siting of new facilities in the United States is a controversial issue that is not addressed analytically.

# Appendix 4-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 affects 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 (1)).

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

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 (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

[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.

production[2] discounted at an assumed rate. The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n} \left[ Q_{t,k} * \lambda * P_{t,k} * \left[ \frac{1}{1+disc} \right]^{t-T} \right], \quad \lambda = \begin{cases} 1 & \text{if primary fuel} \\ COPRD & \text{if secondary fuel} \end{cases} \tag{2}$$

where,

| | | |
|---|---|---|
| k | = | fuel type (oil or natural gas) |
| t | = | time period |
| n | = | number of years in the evaluation period |
| disc | = | expected discount rate |
| Q | = | expected production volumes |
| P | = | expected net wellhead price |
| COPRD | = | co-product factor.[3] |

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

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

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{3}$$

where,

| | | |
|---|---|---|
| $PVREV_{T,1}$ | = | present value of expected revenues generated from the primary fuel |
| $PVREV_{T,2}$ | = | present value of expected revenues generated from the secondary fuel. |

## Present Value of Expected Royalty Payments

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

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{4}$$

where,

| | | |
|---|---|---|
| ROYRT | = | royalty rate, expressed as a fraction of gross revenues. |

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 4.

[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.

## 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:

$$PVPRODTAX_T = PVREV_{T,1} * (1 - ROYRT_1) * PRODTAX_1 + PVREV_{T,2} * (1 - ROYRT_2) * PRODTAX_2 \tag{5}$$

where,

PRODTAX = production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

# Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs) and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period.)

## Present Value of Expected Drilling Costs

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

$$PVDRILLCOST_T = \sum_{t=T}^{T+n} \left[ \left[ COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_T + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \right] * \left( \frac{1}{1 + disc} \right)^{t-T} \right] \tag{6}$$

where,

COSTEXP = drilling cost for a successful exploratory well
SR = success rate (1=exploratory, 2=developmental)

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

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

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

## Present Value of Expected Lease Equipment Costs

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

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[ EQUIP_T * \left( SR_1 * NUMEXP_t + SR_2 * NUMDEV_t \right) * \left[ \frac{1}{1 + disc} \right]^{t-T} \right] \qquad (7)$$

where,

EQUIP = lease equipment costs per well.

Present Value of Other Expected Capital Costs

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

$$PVKAP_T = \sum_{t=T}^{T+n} \left[ KAP_t * \left[ \frac{1}{1 + disc} \right]^{t-T} \right] \qquad (8)$$

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:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[ OPCOST_T * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k\right] * \left(\frac{1}{1 + disc}\right)^{t-T} \right] \tag{9}$$

where,

OPCOST = operating costs per well.

## Present Value of Expected Abandonment Costs

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

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[ COSTABN_T * \left[\frac{1}{1 + disc}\right]^{t-T} \right] \tag{10}$$

where,

COSTABN = abandonment costs.

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

# Present Value of Expected Income Taxes

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

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

- Windfall Profits Tax on oil was repealed.
- Investment Tax Credits were eliminated.

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

- 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 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.

**Table 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**<br>G&G[a]<br>Lease Acquisition | **Cost Depletion**[b]<br>G&G<br>Lease Acquisition | **Maximum of Percentage or Cost Depletion**<br>G&G<br>Lease Acquisition |
| Depreciable Costs | **MACRS**[c]<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's<br>**5-year SLM**[d]<br>20 percent of IDC's | **MACRS**<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's | **MACRS**<br>Lease Acquisition<br>Other Capital Expenditures<br>Successful Well Drilling Costs Other than IDC's |
| Expensed Costs | Dry Hole Costs<br>80 percent of IDC's<br>Operating Costs | Dry Hole Costs<br>80 percent of IDC's<br>Operating Costs | Dry Hole Costs<br>80 percent of IDC's<br>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.

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

$$PVTAXBASE_T = \sum_{t=T}^{T+n} \left[ (TREV_t - ROY_t - PRODTAX_t - OPCOST_t - ABANDON_t - XIDC_t - AIDC_t - DEPREC_t - DHC_t) * \left( \frac{1}{1+disc} \right)^{t-T} \right] \tag{11}$$

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 as defined in equations (6), (7), (8), (12), and (13) respectively. 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.

### *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 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:

$$\begin{aligned} XIDC_t = \; & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t + \\ & COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{12}$$

where,

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

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

[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.

| | | |
|---|---|---|
| NUMDEV | = | number of developmental wells. |

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

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

$$\begin{aligned} AIDC_t = \sum_{j=\beta}^{t} \Big[ & \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \; + \\ & COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \; * \\ & DEPIDC_{t-j+1} \; * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \\ & \beta = \begin{cases} T \text{ for } t \leq T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases} \end{aligned} \tag{13}$$

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

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \; + \; COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \tag{14}$$

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.

**Table 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.

## 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 2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

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

$$\begin{aligned} DEPREC_t = \sum_{j=\beta}^{t} \Big[ & \big[(COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j \; + \\ & (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j \; + \; KAP_j\big] * \\ & DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Big], \end{aligned} \tag{15}$$

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

where,

| | | |
|---|---|---|
| j | = | year of recovery |
| β | = | index for write-off schedule |
| 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 $t \leq n+T-m$, 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

$$PVSIT_T = PVTAXBASE_T * STRT \tag{16}$$

where,

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

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

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{17}$$

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

[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.

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 4-B.  LNG Cost Determination Methodology

## Introduction

The expected LNG import volumes will respond to the projected gas prices at the point of delivery into the U.S. pipeline network. That is, the unit cost of imported LNG[1] will be compared to the cost of other gas available to the pipeline network at that location. Unit LNG costs will be computed as the project revenue at the breakeven point, averaged over expected throughput. The proposed methodology comprises a generalized computation of LNG project costs. These costs serve as the minimum price at which the associated volumes would flow.

The LNG project investment will have a positive expected discounted cash flow when the price exceeds the computed delivered cost (including taxes), which is comprised of three components distinguished with respect to the separate operational phases: liquefaction, shipping, and regasification. Each cost component will be expressed as the cost incurred at each phase to supply a unit of LNG.

The proposed method is intended to be transparent, representative of economic costs, and accounting for some degree of tax liability. The specific level of costs may be affected by local factors that vary costs or tax liability between countries. The sole operational phase on U.S. soil is the regasification terminals. The cost of taxes for these facilities will be determined on the basis of the relevant tax law provisions, including the Modified Accelerated Cost Recovery System (MACRS). Operational phases involving non-U.S. capital (liquefaction facilities and tankers) will represent the tax liability associated with these facilities as property taxes.[2]

$$DCST_t = LIQCST_t + SHPCST_t + RGASCST_t \tag{1}$$

where,

| | | |
|---|---|---|
| $t$ | = | forecast year |
| $DCST_t$ | = | delivered cost per unit of LNG |
| $LIQCST_t$ | = | liquefaction cost per unit of LNG |
| $SHPCST_t$ | = | shipping cost per unit of LNG |
| $RGASCST_t$ | = | regasification cost per unit of LNG. |

A brief description of these components is presented below, followed by the actual formulas used for these estimations.

## Liquefaction

The liquefaction revenue requirement is composed of capital costs, operation and maintenance costs, and miscellaneous costs, as follows:

---

[1]A unit of LNG will be measured as a thousand cubic feet equivalent of the regasified LNG.

[2]This approach, while a severe simplification of a highly complex reality, is a practical alternative that is consistent with the method used in a Gas Research Institute study (1988) and the recent National Petroleum Council study (1992).

$$LIQCST_t = \frac{CAPCSTS_{L,t} + OMCSTS_{L,t} + MSCSTS_{L,t}}{UTIL_{L,t} * CPCTY_{L,t}} \tag{2}$$

where,

| | | |
|---|---|---|
| $LIQCST_t$ | = | liquefaction cost per unit of LNG |
| $CAPCSTS_{L,t}$ | = | capital costs (millions of dollars) |
| $OMCSTS_{L,t}$ | = | operation and maintenance costs (millions of dollars) |
| $MSCSTS_{L,t}$ | = | miscellaneous costs (including production costs) (millions of dollars) |
| $UTIL_{L,t}$ | = | utilization rate (percent) |
| $CPCTY_{L,t}$ | = | gas input capacity (billion cubic feet). |

Capital costs are derived from a rate base that includes equipment costs for gas pretreatment, liquefaction process, utilities, storage, loading facilities, marine facilities, overhead, engineering, fees, and infrastructure costs. The debt/equity ratio, cost of capital, and the tax rate are essential in calculating these costs. Additionally, a method of depreciation, such as the straight line method, must be established for the investment. Capital costs are represented by the following equation:

$$CAPCSTS_{L,t} = DEP_{L,t} + INTR_{L,t} + ROE_{L,t} + TAX_{L,t} \tag{3}$$

where,

| | | |
|---|---|---|
| $CAPCSTS_{L,t}$ | = | capital costs |
| $DEP_{L,t}$ | = | depreciation ($INVST_L/n_L$) |
| $INVST_L$ | = | capital investment (millions of dollars) |
| $n_L$ | = | useful life of investment |
| | | |
| $INTR_{L,t}$ | = | interest on debt ($RBASE_{L,t} * d_L * kd_L$) |
| $RBASE_{L,t}$ | = | rate base ($INVST_L$ - $ACCDEP_{L,t}$) |
| | | |
| $ACCDEP_{L,t}$ | = | accumulated depreciation ($\sum_{y=1}^{t} DEP_{L,y}$) |
| $d_L$ | = | debt financing amount (fraction) |
| $kd_L$ | = | cost of debt (percent) |
| y | = | year of investment |
| | | |
| $ROE_{L,t}$ | = | return on equity ($RBASE_{L,t} * e_L * ke_L$) |
| $e_L$ | = | equity financing amount (1 - $d_L$) (fraction) |
| $ke_L$ | = | cost of equity (percent) |
| | | |
| $TAX_{L,t}$ | = | tax on capital ($INVST_L * TRATE_L$) |
| $TRATE_L$ | = | tax rate (percent). |

Operation and maintenance costs include raw materials, labor, materials, general plant, direct costs, and insurance. Miscellaneous costs include production and feed gas costs.

The utilization rate is represented as a percentage of the sustainable capacity. For both liquefaction and regasification, a buildup period toward the maximum utilization rate may be included as an assumption to reflect a scenario that is more consistent with the historical experience of LNG projects.

## Shipping

The shipping component of the delivered cost also consists of capital costs, operation and maintenance costs, and miscellaneous costs, as represented by the following:

$$SHPCST_t = \frac{CAPCSTS_{s,t} + OMCSTS_{s,t} + MSCSTS_{s,t}}{VOLYR_{s,t}} \tag{4}$$

where,

| | | |
|---|---|---|
| $SHPCST_t$ | = | shipping cost per unit of LNG |
| $CAPCSTS_{s,t}$ | = | capital costs (millions of dollars) |
| $OMCSTS_{s,t}$ | = | operation and maintenance costs (millions of dollars) |
| $MSCSTS_{s,t}$ | = | miscellaneous costs (millions of dollars) |
| $VOLYR_{s,t}$ | = | shipping volume per year (billion cubic feet). |

Again, key components in calculating capital costs are the type of financing and the cost of financing. Capital costs are represented as follows:

$$CAPCSTS_{s,t} = DEP_{s,t} + INTR_{s,t} + ROE_{s,t} + TAX_{s,t} \tag{5}$$

where,

| | | |
|---|---|---|
| $CAPCSTS_{s,t}$ | = | capital costs |
| $DEP_{s,t}$ | = | depreciation ($INVST_s/n_s$) |
| $INVST_s$ | = | capital investment (millions of dollars) |
| $n_s$ | = | useful life of investment |
| | | |
| $INTR_{s,t}$ | = | interest on debt ($RBASE_{s,t}$ * $d_s$ * $kd_s$) |
| $RBASE_{s,t}$ | = | rate base ($INVST_s$ - $ACCDEP_{s,t}$) |
| | | |
| $ACCDEP_{s,t}$ | = | accumulated depreciation ($\sum_{y=1}^{t} DEP_{s,y}$ ) |
| $d_s$ | = | debt financing amount (fraction) |
| $kd_s$ | = | cost of debt (percent) |
| y | = | year of investment |
| | | |
| $ROE_{s,t}$ | = | return on equity ($RBASE_{s,t}$ * $e_s$ * $ke_s$) |
| $e_s$ | = | equity financing amount (1 - $d_s$) (fraction) |
| $ke_s$ | = | cost of equity (percent) |
| | | |
| $TAX_{s,t}$ | = | tax on capital ($INVST_s$ * $TRATE_s$) |
| $TRATE_s$ | = | tax rate (percent). |

Operation and maintenance costs for shipping include those for crew, repair, administrative and general overhead, and insurance.

A key element in the operating costs for shipping is the distance that the LNG must travel. This distance will affect the amount of LNG that can be transported annually, and ultimately will affect the annual unit cost of transporting gas. Assumptions about average speed, operating days per year, and boiloff LNG used for fuel also affect the calculation of shipping volume per year. The calculation for finding the volume that can be shipped per year is represented as follows:

$$VOLYR_{s,t} = VLTRIP_{s,t} * TRIPS_{s,t} \tag{6}$$

where,

| | | |
|---|---|---|
| $VOLYR_{s,t}$ | = | shipping volume per year (billion cubic feet) |
| $VLTRIP_{s,t}$ | = | volume per trip ($CPCTY_{s,t}$ - $BOILTRP_{s,t}$) (billion cubic feet) |
| $CPCTY_{s,t}$ | = | shipping capacity (billion cubic feet) |
| $BOILTRIP_{s,t}$ | = | boiloff per trip [$BOILDAY_{s,t}$ * ($HOURS_{s,t}$/24)] (billion cubic feet) |
| $BOILDAY_{s,t}$ | = | boiloff per day (billion cubic feet) |
| $HOURS_{s,t}$ | = | hours per round-trip (2 * $MILES_{s,t}$/$SPEED_{s,t}$) |
| $MILES_{s,t}$ | = | one-way distance (nautical miles) |
| $SPEED_{s,t}$ | = | average speed of trip (nautical miles per hour) |
| $TRIPS_{s,t}$ | = | trips per year ($OPDAYS_{s,t}$/$DAYS_{s,t}$) |
| $OPDAYS_{s,t}$ | = | operating days per year. |
| $DAYS_{s,t}$ | = | days per trip ($HOURS_{s,t}$/24 + $PORT_{s,t}$) |
| $PORT_{s,t}$ | = | port days per round-trip |

Miscellaneous costs include tankers fuel costs (nitrogen and bunker) and port costs.

## Regasification

Regasification terminals consist of capital and operation and maintenance costs, as shown in the following:

$$RGASRR_{t} = \frac{CAPCSTS_{r,t} + OMCSTS_{r,t}}{UTIL_{r,t} * CPCTY_{r,t}} \tag{7}$$

where,

| | | |
|---|---|---|
| $RGASRR_{t}$ | = | regasification cost per unit of LNG |
| $CAPCSTS_{r,t}$ | = | capital costs (millions of dollars) |
| $OMCSTS_{r,t}$ | = | operation and maintenance costs (millions of dollars) |
| $UTIL_{r,t}$ | = | utilization rate (percent) |
| $CPCTY_{r,t}$ | = | terminal capacity (billion cubic feet). |

For existing terminals, original capital expenditures are considered sunk costs. The capital outlays for both re-activation and expansion are examined, along with costs of capital, method of financing, and tax rates. These capital costs can be represented as follows:

$$CAPCSTS_{r,t} = RSCAP_{r,t} + EXCAP_{r,t} \tag{8}$$

where,

$RSCAP_{r,t}$ = restart capital costs
$EXCAP_{r,t}$ = expansion capital costs.

Both of these capital expenditures[3] can be represented in the same way as the capital costs for liquefaction or shipping. The formulae are as follows:

$$RSCAP_{r,t} = RSDEP_{r,t} + RSINTR_{r,t} + RSROE_{r,t} + RSTAX_{r,t} \tag{9}$$

where,

$RSDEP_{r,t}$ = depreciation ($RSINVST_r$*$RSDRATE_{r,t}$)
$RSINVST_r$ = capital investment in re-activation (millions of dollars)
$RSDRATE_{r,t}$ = depreciation rate

$RSINTR_{r,t}$ = interest on debt ($RSRBASE_{r,t}$ * $d_r$ * $kd_r$)
$RSRBASE_{r,t}$ = rate base ($RSINVST_r$ - $RSACCDEP_{r,t}$)
$RSACCDEP_{r,t}$ = accumulated depreciation ($\sum_{y=1}^{t} RSDEP_{r,y}$ )
$d_r$ = debt financing amount (fraction)
$kd_r$ = cost of debt (percent)
y = year of re-activation

$RSROE_{r,t}$ = return on equity ($RSRBASE_{r,t}$ * $e_r$ * $ke_r$)
$e_r$ = equity financing amount (1 - $d_r$) (fraction)
$ke_r$ = cost of equity (percent)

$RSTAX_{r,t}$ = tax on capital ($RSINVST_r$ * $RSTRATE_r$)
$RSTRATE_r$ = tax rate (percent).

and,

$$EXCAP_{r,t} = EXDEP_{r,t} + EXINTR_{r,t} + EXROE_{r,t} + EXTAX_{r,t} \tag{10}$$

where,

$EXDEP_{r,t}$ = depreciation ($EXINVST_r$*$EXDRATE_{r,t}$)
$EXINVST_r$ = capital investment in expansion (millions of dollars)
$EXDRATE_{r,t}$ = depreciation rate

$EXINTR_{r,t}$ = interest on debt ($EXRBASE_{r,t}$ * $d_r$ * $kd_r$)
$EXRBASE_{r,t}$ = rate base ($EXINVST_r$ - $EXACCDEP_{r,t}$)

$EXACCDEP_{r,t}$ = accumulated depreciation ($\sum_{y=1}^{t} EXDEP_{r,y}$ )

[3]In practice, it is not expected that both restarting an existing facility and capacity expansion at the same site would occur in the same year. Thus, RSCAP and EXCAP are not expected to both be nonzero in the same year.

$d_r$ = debt financing amount (fraction)
$kd_r$ = cost of debt (percent)
$y$ = year of expansion

$EXROE_{r,t}$ = return on equity ($EXRBASE_{r,t}$ * $e_r$ * $ke_r$)
$e_r$ = equity financing amount (1 - $d_r$) (fraction)
$ke_r$ = cost of equity (percent)

$EXTAX_{r,t}$ = tax on capital ($EXINVST_r$ * $EXTRATE_r$)
$EXTRATE_r$ = tax rate (percent).

Operating and maintenance costs for a regasification terminal include: terminaling and processing, labor, storage, administrative and general overhead.

# Appendix 4-C.  Finding Rate Methodology

# Introduction

The purpose of this appendix is to describe the finding rate methodology in the Oil and Gas Supply Module (OGSM). The finding rate methodology represents the process by which oil and gas in the unproved portion of the economically recoverable resource base[1] convert to proved reserves.[2] This appendix begins with a discussion of the basic finding rate methodology utilized in OGSM. This includes a presentation of a simple finding rate equation, as well as successive adaptations to accommodate the particular nature of the resource estimates and to incorporate the effects of technological change. Next, there is a description of the implementation of this methodology in OGSM, focusing on modifications consistent with the model's resource accounting system.

# Basic Finding Rate Methodology

The finding rate measures the yield from exploratory drilling, that is, the amount of reserves discovered per unit of exploratory drilling. A basic assumption underlying the finding rate methodology in OGSM is that the larger the oil or gas field, the greater the probability that it will be discovered. Another is that large oil and gas fields, though fewer in number, contain a disproportionate amount of total resources. These assumptions suggest that finding rates will decline as drilling progresses. The exact nature of this decline is subject to debate, but one or another form of exponential decline has been utilized by several well known discovery process models.[3] OGSM borrows from these models in assuming an exponentially declining finding rate relationship between cumulative reserves discovered and cumulative exploratory drilling. The basic finding rate equation in OGSM reflects this relationship. Given an initial finding rate, FR0, an increase in the cumulative drilling leads to an exponential decline in the finding rate.[4] This may be expressed in equation form as:

$$FR = FR0 * \exp(-\delta * SW) \tag{1}$$

where,

| | | |
|---|---|---|
| FR | = | finding rate (Mbbl per well or MMcf per well) |
| SW | = | cumulative successful exploratory wells |
| $\delta$, FR0 | = | parameters. |

The derivation of the parameter $\delta$, the exponential decline factor, is based on the properties inherent in Equation (1). In the limit, the amount of economic oil or gas discovered equals the level of undiscovered oil or gas (Q). This relationship can be expressed as the integral of the finding rate over an infinite number of successful wells (Equation (2)).

---

[1] *Economically recoverable resources* are those volumes considered to be of sufficient size and quality for their production to be commercially profitable by current conventional technologies, under specified economic assumptions. Economically 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. On the other hand, *technically recoverable resources* are those volumes producible with current recovery technology and efficiency but without reference to economic viability.

[2] *Proved reserves* are the estimated quantities that analysis 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] See, for example, Arps, J.J. and T.G. Roberts. 1958.

[4] As will be shown, the finding rate implemented in OGSM declines exponentially within each period, but not exponentially over the entire forecast, as $\delta$ is recalculated each year based on a different estimate for the remaining economically recoverable resource base.

$$Q = \int_0^\infty FRO * \exp(-\delta * SW) d(SW) \tag{2}$$

It follows that the rate of decline (δ) can be expressed as the simple ratio of the initial finding rate (FR0) to the remaining undiscovered resource base (Q). From Equation (2),

$$\begin{aligned} Q &= \int_0^\infty FR0 * \exp(-\delta * SW) d(SW) \\ &= \frac{FR0}{-\delta} \int_0^\infty \exp(-\delta * SW) * (-\delta) * d(SW) \\ &= (-\frac{FR0}{\delta}) * \exp(-\delta * SW) \Big|_{SW=0}^{SW=\infty} \\ &= (-\frac{FR0}{\delta}) * (0-1) \\ &= \frac{FR0}{\delta} \end{aligned} \tag{3}$$

or,

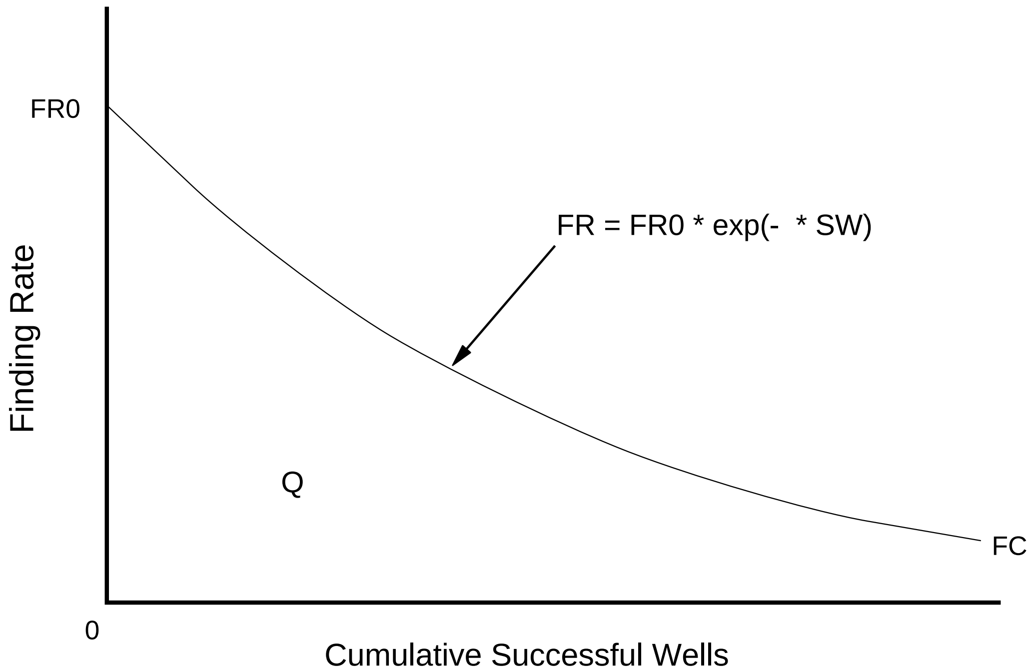
$$\delta = \frac{FR0}{Q} \tag{4}$$

From Equation (4) one can see that a smaller resource base estimate would result in a more rapid decrease in productivity, indicated by a larger value of δ. An important aspect of Equation (4) is that the denominator represents *remaining* recoverable resources as of the period corresponding to the origin for the specified function. This attribute is especially germane to the introduction of technology into the finding rate, which is discussed later in this appendix.

The basic finding rate methodology in OGSM can be further illustrated by a simple graphic presentation of the preceding concepts. The curve FC in Figure 11 represents the finding rate function described by Equation (1). The point at which FC intersects with the y-axis is the initial finding rate, FR0. In accordance with the previous discussion, the finding rate decreases exponentially along the x-axis, which represents cumulative drilling (SW). The decline in the finding rate curve FC is determined by the exponential rate of decline (δ), derived in Equation (4) above as a function of the initial finding rate and the ultimate resource target, Q.

Given this methodology, the level of reserve additions in period t can be calculated as the integral of the finding rate Equation (1) over the range of cumulative successful exploratory wells from the previous period, t-1, through the current forecast year. This may be expressed in equation form as:

**Figure 11. Basic Finding Rate Function**



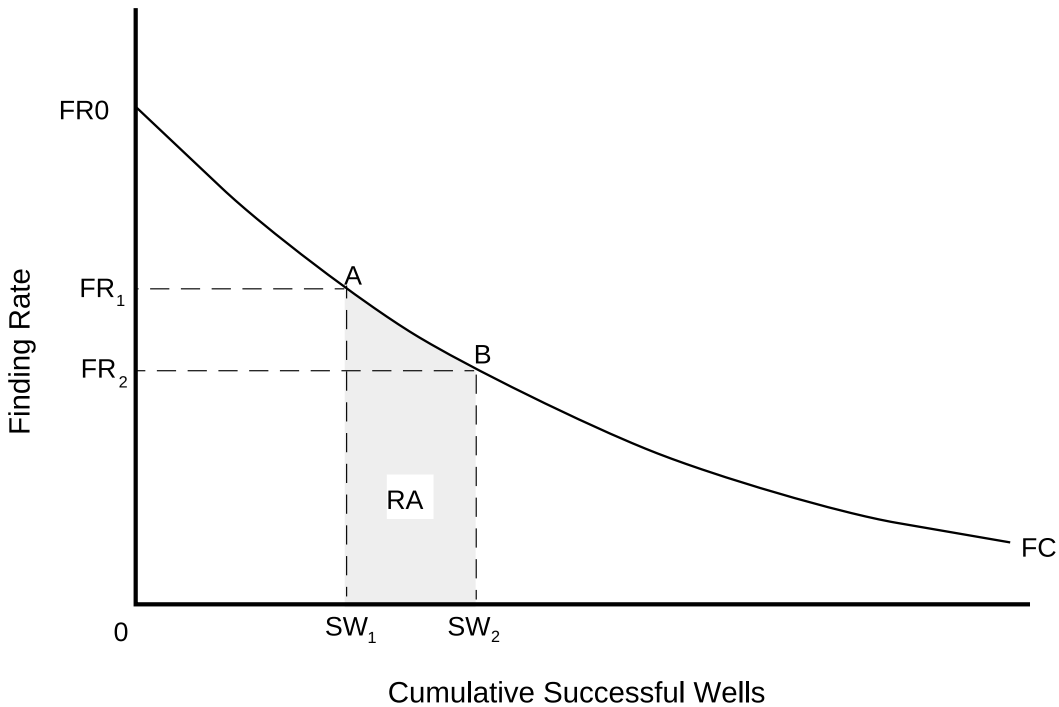

$$RA_t = \left(\frac{FR0}{\delta}\right) * \left[\exp(-\delta * SW_{t-1}) - \exp(-\delta * SW_t)\right] \tag{5}$$

where,

| | | |
|---|---|---|
| t | = | forecast year |
| RA | = | reserve additions from exploratory drilling |
| SW | = | cumulative successful exploratory wells |
| $\delta$, FR0 | = | parameters. |

Reserve additions are graphically represented in Figure 12. The area beneath the curve FC stands for the remaining undiscovered resource base (Q). Any segment of this total area, as determined by movement along the x-axis, represents the amount of reserve additions (RA) discovered as a result of the indicated change in cumulative drilling. Accordingly, an increase in cumulative drilling from $SW_1$ to $SW_2$ would result in a quantity of discoveries defined by the segment A-B-$SW_2$-$SW_1$. In this case the finding rate declines from $FR_1$ to $FR_2$ as drilling increases from $SW_1$ to $SW_2$.

**Figure 12. Reserve Additions**

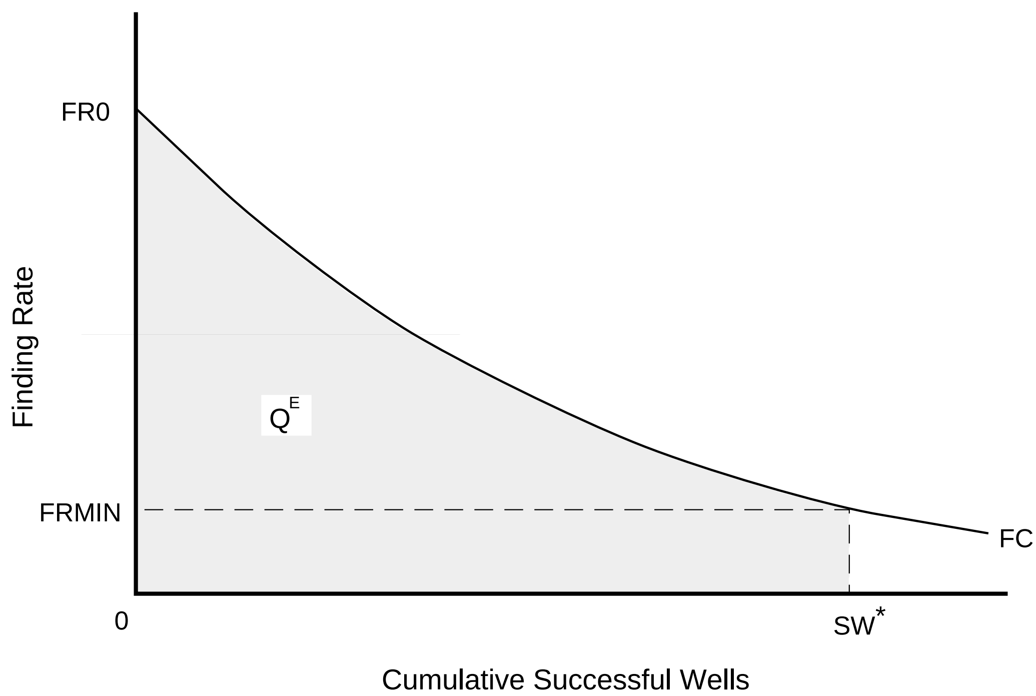



## Minimum Economic Finding Rate

The Q parameter as described previously is the total resource base, which is recoverable only with an infinite number of wells. The resource estimates employed in OGSM, however, represent only the resources that are economically recoverable. Implicit in these estimates is the existence of some minimum physical return to exploratory drilling that would make such activities profitable enough to be undertaken. This concept is represented in OGSM in the form of a minimum economic finding rate (FRMIN). The minimum economic finding rate is presented in Figure 13. FRMIN is reached when cumulative successful wells increase to $SW^*$. The undiscovered economically recoverable resource base ($Q^E$) is represented by the shaded area beneath the finding rate curve (FC) and left of the drilling level at which the curve intersects with FRMIN.

By utilizing the concept of a minimum economic finding rate, it is possible to obtain an estimate of $\delta$ that is based on the economically recoverable resource base, yet is consistent with the methodology proposed in Equations (3) and (4). Equation (3) now becomes:

**Figure 13. Minimum Economic Finding Rate**




$$
\begin{aligned}
Q^E &= \int_0^{SW^*} FR0 * \exp(-\delta * SW) d_{SW} \\
&= \frac{FR0}{-\delta} \int_0^{SW^*} \exp(-\delta * SW) * (-\delta) * d_{SW} \\
&= \left(-\frac{FR0}{\delta}\right) * \exp(-\delta * SW)\Big|_{SW=0}^{SW=SW^*} \\
&= \left(-\frac{FR0}{\delta}\right) * (\exp(-\delta * SW^*) - 1) \\
&= \frac{FR0 - FR0 * (\exp(-\delta * SW^*))}{\delta}
\end{aligned}
\tag{6}
$$

where,

| | | |
|---|---|---|
| $SW^*$ | = | level of cumulative drilling at which minimum economic finding rate is attained |
| $Q^E$ | = | undiscovered economically recoverable resource base. |

Since FR0*exp(-$\delta$*$SW^*$) is equivalent to FRMIN, Equation (4) converts to:

$$\delta = \frac{(FR0 - FRMIN)}{Q^E} \tag{7}$$

## Technological Change

While the OGSM methodology assumes that increases in cumulative drilling lowers the finding rate, the methodology permits this decline to be partially, fully, or more than fully offset by improvements in technology. Specifically, the methodology adopts the "Technological Stretch" approach advanced by William Fisher.[5] In this paradigm, technological change shifts the finding rate function upwards, mitigating the progression from larger to smaller fields. The advantage of this approach is that it is capable of modeling finding rates that rise, remain constant, or decline over time depending on the values of the technology and resource decline parameters.

The treatment of technological change is illustrated in Figure 14. Given an intial economically recoverable resource base $Q^E$, the section A-B- $SW_2$-$SW_1$ represents the reserves that that would be added as a result of a drilling increase from $SW_1$ to $SW_2$. If, concurrent to this increase in drilling, there are technological advances that cause the remaining economically recoverable resource base to increase by an amount $\Delta_1$ $Q^E$, the operative finding rate curve becomes $FC_{1.}$ $FC_1$ reflects the increase in the finding rate brought about by expanded resource base. The amount of extra reserve additions due to technological change is then defined by the area A-A'-C-B. Simarily, when cumulative drilling increases from $SW_2$ to $SW_3$, and accompany advances in technology cause the remaining economically recoverable resource base to expand by an amount $\Delta_2$ $Q^E$, there is a further shift in the finding rate function to $FC_2$. Reserve additions are again increased over what they otherwise would have been, this time by the area C-C'-F-E. This latter increase is incremental to the extra reserves discovered as a result of the technological advances that transpired as drilling progressed from $SW_1$ to $SW_2$. (The area defined by B-C-E-D).

From equation (1), in the absence of technological change, the finding rate at the end of period t is lower than the finding rate in period t-1 by $\delta$ times the number of wells drilled in period t, i.e.

$$FR_t = FR_{t-1} * \exp(-\delta*(SW_t - SW_{t-1})). \tag{8a}$$

In the presence of technological change this relationship is amended to incorporate the technology parameter $\beta$:

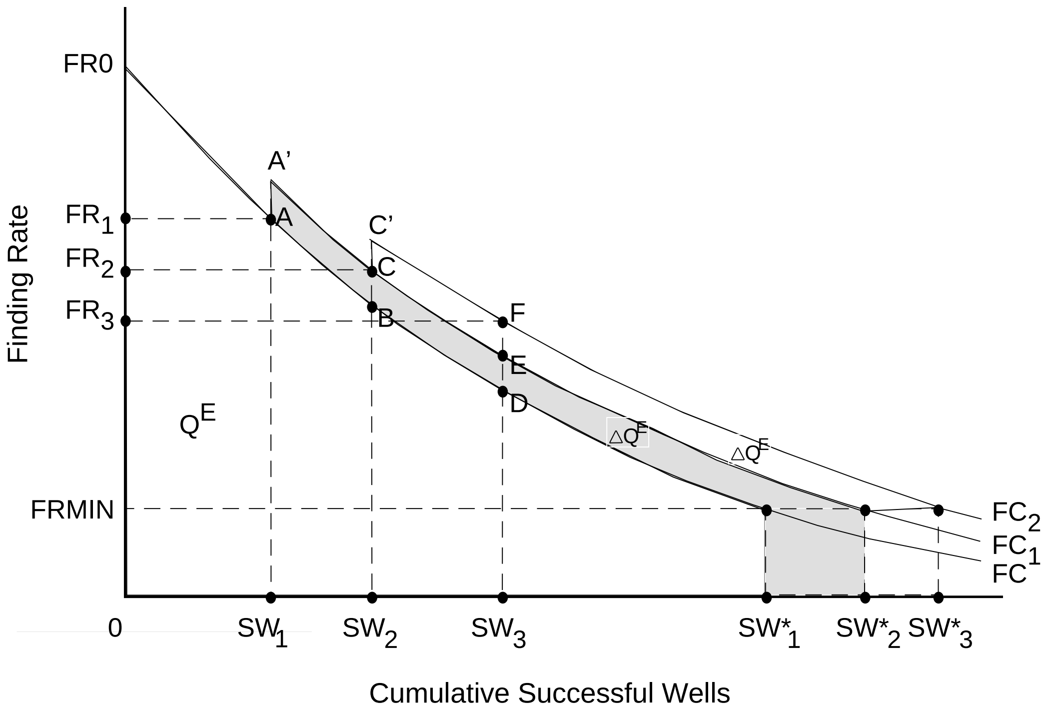
$$FR_t = FR_{t-1} * (1+ \beta) * \exp(-\delta*(SW_t - SW_{t-1})). \tag{8b}$$

The inclusion of this parameter permits the finding rate in period t to be higher, lower, or equal to the finding rate in t-1 depending on the value of $\beta$, $\delta$, and the number of wells drilled in period t.

Technological change also impacts the rate of decline in the finding rate with respect to cumulative drilling. Specifically, because the remaining recoverable volume is expanding relative to what it otherewise would have been, $\delta$ must be recalculated in each period as shown in equation (9). Note that the denominator of (9) is the

[5]Fisher, W.L. "U.S. Oil and Gas Resources: Their Critical Dependency on Technology," unpublished manuscript, 1994.

**Figure 14. Technological Change**




remaining economically recoverable resource base estimate calculated as the initial economically recoverable resource base adjusted for expansion due to technological change, less the cumulative reserves found over time.

$$\delta_t = \frac{FR_{t-1} * (1+\beta) - FRMIN}{QTECH_t - CUMRES_{t-1}} \tag{9}$$

where,

| | | |
|---|---|---|
| FR | = | finding rate at the beginning of period |
| FRMIN | = | minimum economic finding rate |
| QTECH | = | initial economically recoverable resource base adjusted for expansion due to technological change |
| t | = | forecast year |
| CUMRES | = | cumulative reserve discoveries over the projection period (initial value = 0). |

As indicated in Equation (8) the resource base is assumed to expand over time due to the development of new discovery and extraction technologies, as well as the increased penetration of existing technologies. This technology-induced expansion is modelled in OGSM by allowing the initial resource base to expand each year at an assumed constant rate of expansion. For undiscovered resources this rate of expansion is determined as the rate necessary for initial economically recoverable resources to reach in the final year of the forecast a level equivalent to the level of resources technically recoverable under existing technology. For inferred reserves there is some technology-induced expansion implicit in initial resource levels. In some cases (deep drilling depths onshore and shallow water depths offshore) the initial levels of inferred reserves are augmented by constant annual percentage increases determined by analytical judgement. For both undiscovered resources and (those affected) inferred reserves the representation of the technologically expanded resource base becomes:

$$QTECH_t = I * (1 + TECH)^{t-T} \tag{10}$$

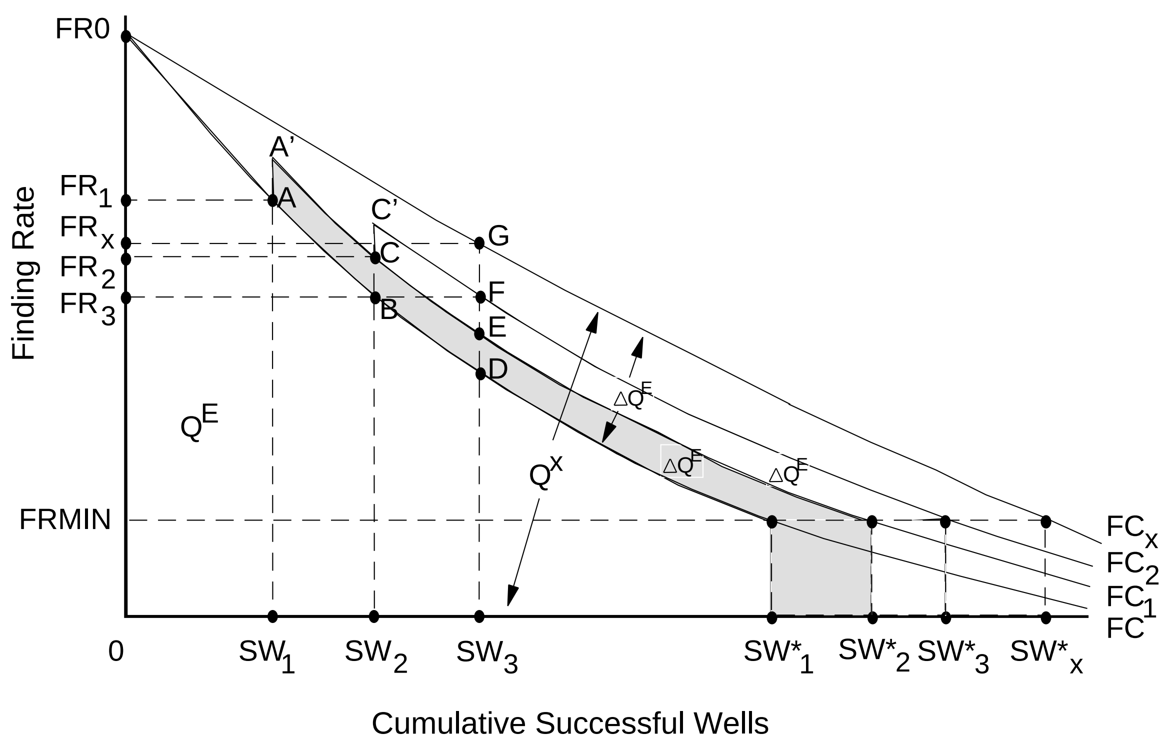
where,

| | | |
|---|---|---|
| I | = | initial inferred reserves estimate in year T |
| TECH | = | annual percentage expansion of resource base due to technological change. |

In Figure 14 the total expected expansive effect of advancing technology upon the recoverable resource base is introduced in increments. This approach compares to one in which a larger initial resource value is used to determine a δ that remains constant over time. With that the full long-term benefits of tecnological change are factored into the determination of the finding rate curve for all years of the forecast horizon. Figure 15 provides a graphical comparison of these two approaches in the early years. $FC_x$ is the finding rate curve derived by calculating a constant δ based on FR0 and a resource base, $QTECH_{25}$, that reflects the full expected benefits of technological change for the entire forecast horizon. In this case the section defined by FR0-G-$SW_3$-0 represents the reserve additions that would be estimated as a result of utilizing the "full benefit" approach.

The finding rate curves relating to onshore conventional inferred reserves and offshore gas inferred reserves partially reflect the “full benefit” approach. This is because estimates of these resources inherently contain some allowance for long-term technological progress due to their incorporation of historical rates of reserve growth. In previous versions of the model this approach was considered inappropriate from a theoretical standpoint. That is, it was thought that technological developments in the later years of the forecast period should not be “providing benefits” in the early years of the forecast. After further analysis, however, it has been determined that this approach is acceptable in these cases, given the nature of inferred reserves and the manner in which estimates

**Figure 15. Technological Change: Incremental versus Full Benefit Approach**



of inferred reserves are utilized to determine the rate of decline in the finding rate function.

## Implementation of the Finding Rate Methodology

The finding rate process actually implemented in OGSM is somewhat more complex than the simple structure portrayed above, although the underlying concepts remain the same. The changes to the basic design mostly reflect the reserve accounting system instituted in OGSM. In the previous Energy Information Administration (EIA) supply model, the Production of Onshore Lower 48 Oil and Gas Model (PROLOG), reserve additions were treated primarily as a function of undifferentiated exploratory drilling. The relatively small amount of reserve additions from other sources was represented as coming from developmental drilling. Reserve additions from developmental drilling were not related directly to exploratory activity.

In the Oil and Gas Supply Model (OGSM) there is a distinction between exploratory drilling for new fields and exploratory drilling for additional deposits within old fields.[6] This enhancement recognizes important differences in exploratory drilling, both by nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields into both proved reserves (as new discoveries) and inferred reserves.[7] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves by a phenomenon termed reserves growth, the process by which initial assessments of proved reserves from a new field discovery grow over time. The volumetric returns to other exploratory and developmental drilling in OGSM are referred to as extensions and revisions, respectively. Other exploratory drilling accounts for proved reserves added through new pools or extensions (generally referred to only as extensions within the context of the model), and development drilling accounts for reserves added as net revisions (including adjustments). The finding rate equations vary in OGSM among new field wildcats, other exploratory drilling, and developmental drilling. Finding rates are defined separately for each fuel type category (k) in each region (r).

### *New Field Wildcat Finding Rates*

The finding rate equation (Equation (21)) for new field wildcats[8] follows rather closely the basic methodology described above. In the OGSM specification, the yield from new field wildcat drilling begins at the initial finding rate, FR1, and declines exponentially thereafter. This specification conforms to the design of Equation (1).

$$FR1_{r,k,t} = FR1_{r,k,t-1}(1+\beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) \qquad (11)$$

where,

| | | |
|---|---|---|
| FR1 | = | finding rate (Mbbl per well or MMcf per well) |
| SW1 | = | successful new field wildcats |

[6]Exploratory wells are drilled in relatively untested or unproven areas and can result in the discovery of new fields or new pools within known fields. Exploratory drilling in OGSM is divided between two major types. *New field wildcats* are exploratory 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. *Developmental wells* are primarily within or near proven areas and can result in extensions or revisions.

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

[8]Total successful exploratory wells as described previously are disaggregated into successful new field wildcats and other exploratory wells. The disaggregation is based on average historical ratios of successful new field wildcats to total successful exploratory wells. For the rest of this appendix, successful new field wildcats will be designated by the variable SW1, other successful exploratory wells by SW2, and successful development wells by SW3.

$\delta 1$ = finding rate decline parameter
$\beta 1$ = technology parameter for FR1
r = region
k = fuel type (oil or gas).

New field reserve additions are determined as the integral of the finding rate function over the given drilling interval, ($SW1_{r,k,t}$). The resource base enters the equation as an exogenous input that influences the derivation of $\delta 1$, the finding rate decline parameter. The value of the technology parameter, $\beta 1$, was based on an econometric analysis of the impact of technology on the new field wildcat finding rate. The decline parameter, $\delta 1$, is estimable from Equation (9) in combination with the terms of Equations (10) and (13). Substituting values specific to new field wildcat wells yields the following equation:

$$\delta 1_{r,k,t} = \frac{FR1_{r,k,t-1}(1+\beta 1) - FRMIN1_{r,k}}{Q^{E}_{r,k} + (Q^{E}_{r,k} * (1+TECH)^{25}/\phi - Q^{E}_{r,k}) * (1 - \exp(-\gamma t)) - \sum_{T+1}^{t-1} \int FR1_{r,k,t} d(SW1)} \tag{12}$$

where,

FRMIN1 = minimum economic finding rate for new field wildcat wells.

The initial estimate for proved reserves are reserves that can be certified using mainly the original discovery wells, while inferred reserves are those hydrocarbons that will require additional drilling before they can be considered proved. Subsequent drilling takes the form of 'other exploratory' drilling and development drilling. The finding rates for these latter two types of drilling are based on the same methodology described above, with appropriate modifications to account for differences in the nature of the resource target and the process by which it is converted to proved reserves.

The volumetric yield from a successful new field wildcat well is divided into proved reserves and inferred reserves based on historical reserves growth statistics. More specifically, the allocation of reserves between proved and inferred reserves is based on the average ratio of initial reserves estimated for a newly discovered field relative to ultimate recovery from the field.[9] 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. The new fields discovered by new field wildcats yield not only proved reserves but also a much larger amount of inferred reserves. Specifically, the change in proved reserves from new field discoveries for each period is given by:

$$\Delta R_{r,k,t} = \frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t}\ d(SW1)$$
$$\frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t-1}(1+\beta 1) * \exp(-\delta 1_{r,k,t} * SW1_{r,k,t}) d(SW1 \tag{13}$$

where,

[9]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.*

| | | |
|---|---|---|
| X | = | reserves growth factor |
| $\Delta R$ | = | additions to proved reserves. |

The terms in Equation (23) are all constants in period t, except for the SW1. X is derived from the historical data and it is assumed to be constant during the forecast period. $FR1_{r,k,t-1}$ and $\delta1_{r,k,t}$ are calculated prior to period t, based on lagged variables and fixed parameters as shown in Equations (21) and (22).

***Finding Rates for Other Types of Drilling***

Reserves are assumed to move from the realm of inferred to proved with the drilling of other exploratory wells or developmental wells in much the same way as volumes of both proved and inferred reserves are modeled as moving from the undiscovered economically recoverable resource base as described above. The volumetric return to other exploratory wells and developmental wells is shown in Equations (24) and and (25), respectively.

$$FR2_{r,k,t} = FR2_{r,k,t-1}(1+\beta2) * \exp(-\delta2_{r,k,t} * SW2_{r,k,t}) \tag{14}$$

where,

| | | |
|---|---|---|
| FR2 | = | other exploratory wells finding rate |
| SW2 | = | successful other exploratory wells |
| $\beta2$ | = | technology parameter for FR2. |

$$FR3_{r,k,t} = FR3_{r,k,t-1}(1+\beta3) * \exp(-\delta3_{r,k,t} * SW3_{r,k,t}) \tag{15}$$

where,

| | | |
|---|---|---|
| FR3 | = | development well finding rate |
| SW3 | = | successful development wells |
| $\beta3$ | = | technology parameter for FR3. |

The derivation of updated decline factors for the exponentially declining functions are shown in Equations (26) and (27) for other exploratory drilling and developmental drilling, respectively.

$$\delta2_{r,k,t} = \left[\frac{(FR2_{r,k,t-1}(1+\beta2) - FRMIN2_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1}(\frac{X-1}{X})\int FR1_{r,k,t}d(SW1) - \sum_{T+1}^{t-1}[\int FR2_{r,k,t}d(SW2) + \int FR3_{r,k,t}d(SW3)]}\right] \tag{16}$$

$$\delta3_{r,k,t} = \left[\frac{(FR3_{r,k,t-1}(1+\beta3) - FRMIN3_{r,k}) * DECFAC}{I_{r,k}(1+TECH)^{t-T} + \sum_{T+1}^{t-1}(\frac{X-1}{X})\int FR1_{r,k,t}d(SW1) - \sum_{T+1}^{t-1}[\int FR2_{r,k,t}d(SW2) + \int FR3_{r,k,t}d(SW3)]}\right] \tag{17}$$

where,

| | | |
|---|---|---|
| I | = | initial inferred reserves estimate |
| DECFAC | = | decline rate adjustment factor. |
| FRMIN2 | = | minimum economic finding rate for other exploratory wells |
| FRMIN3 | = | minimum economic finding rate for developmental wells |

The conversion of inferred reserves into proved reserves occurs as both other exploratory wells and developmental wells exploit a single stock of inferred reserves. The specification of Equations (26) and (27) has the characteristic that the entire stock of inferred reserves can be exhausted through sufficiently large numbers of either the other exploratory wells or developmental wells alone. This extreme result is unlikely given reasonable drilling levels in any one year. Nonetheless, the simultaneous extraction from inferred reserves by both drilling types could be expected to affect the productivity of each other. Specifically, the more one drilling type draws down the inferred reserve stock, there could be a corresponding acceleration in the productivity decline of the other type. This is because in a given year the same initial recoverable resource value (i.e., the denominator expression in the derivation of $\delta_2$ and $\delta_3$ ) is decremented by either type of drilling. DECFAC is present in the computation of $\delta_2$ and $\delta_3$ to account for the simultaneous drawdown from inferred reserves by both other exploratory wells and developmental wells. DECFAC is a user-specified parameter that should be greater than or equal to 1.0. Values greater than 1.0 accelerate the productivity decline in the finding rate.

Integration of the preceding finding rate functions with the new field wildcat function yields the following equation for total reserve additions in period t:

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_{0}^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_{0}^{SW1_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_{0}^{SW1_{r,k,t}} FR3_{r} \qquad (18)$$

## Conclusion

This completes a description of the finding rate methodology utilized in OGSM. A simple basic methodology was presented upon which the OGSM finding rate functions are based. Included in this discussion were descriptions of two modifications to that basic structure—one to account for the economic nature of the resource estimates and another to incorporate the effect of technological advancements. Subsequently, the implementation of this methodology in OGSM was described, with the resulting finding rate functions shown to vary from the basic structure primarily because of the resource accounting system employed in OGSM.

The methodology for conversion of oil or gas resources into proved reserves is a critically important aspect of supply modeling. While the actual process through which oil and gas become proved reserves is a highly complex one, the methodology presented here is representative only of the major phases that occur. By necessity, it is a simplification from a highly complex reality.

# Appendix 4-D. Deep Water Offshore Supply Submodule

The Deepwater Offshore Supply Submodule (DWOSS) is a PC-based modeling system for projecting the reserve additions and production from undiscovered resources in deepwater offshore Gulf of Mexico Outer Continental Shelf (OCS) region.

This chapter discusses in detail the programming structure, design implementation, costing algorithms, and input databases for resource description, technology options, and other key performance parameters that were used to develop the DWOSS modeling system. In the first section, the model components are introduced. This is followed by the process flow diagrams highlighting the major steps involved in each of the components. The chapter includes a characterization of the undiscovered resource base in the deepwater Gulf of Mexico OCS classified by region and resource type (crude oil and natural gas). In the same section, the input database of resource characteristics developed for DWOSS are described. The subsequent section deals with the rationale behind the various technology options for deepwater exploration, development and production practices incorporated in DWOSS. This is followed by a discussion of the typical exploration, development and production scheduling assumed in the model. It covers the well productivity and production profile parameters assumed in DWOSS. The next section describes the unit cost equations utilized in DWOSS to estimate the various costs associated with exploration, development and production operations in the deepwater Gulf of Mexico OCS. This is followed by a discussion of the financial analysis approach and the discounted cash-flow methodology used in DWOSS to determine the profitability of deepwater crude oil and natural gas prospects, and to generate price-supply data. The final section in this chapter deals with the endogenous component of DWOSS that involves calculation of reserves and production for the total deepwater Gulf of Mexico offshore region.

## *INTRODUCTION*

The DWOSS was developed offline from EIA's Oil and Gas Supply Module (OGSM). A methodology was developed within OGSM to enable it to readily import and manipulate the DWOSS output, which consists essentially of detailed price/supply tables disaggregated by Gulf of Mexico planning regions (Eastern, Central, and Western) and fuel type (oil, natural gas). Maps of the three Gulf of Mexico planning regions are presented in Figures 4D-1 through 4D-3.

At the most fundamental level, therefore, it is useful to identify the two structural components that make up the DWOSS, as defined by their relationship (exogenous vs. endogenous) to the OGSM:

***Exogenous Component***. A methodology for developing deepwater offshore undiscovered resource price/supply curves, employing a rigorous field-based discounted cash-flow (DCF) approach, was constructed exogenously from OGSM. This offline portion of the model utilizes key field properties data, algorithms to determine key technology components, and algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable reserves for the different fields are aggregated by planning region and by resource type to generate resource-specific price-supply curves. In addition to the overall supply price and reserves, cost components for exploration, development drilling, production platform, and operating expenses, as well as exploratory and development well requirements, are also carried over to the endogenous component.

Figure 4D-1. Map of Western Gulf of Mexico Planning Area

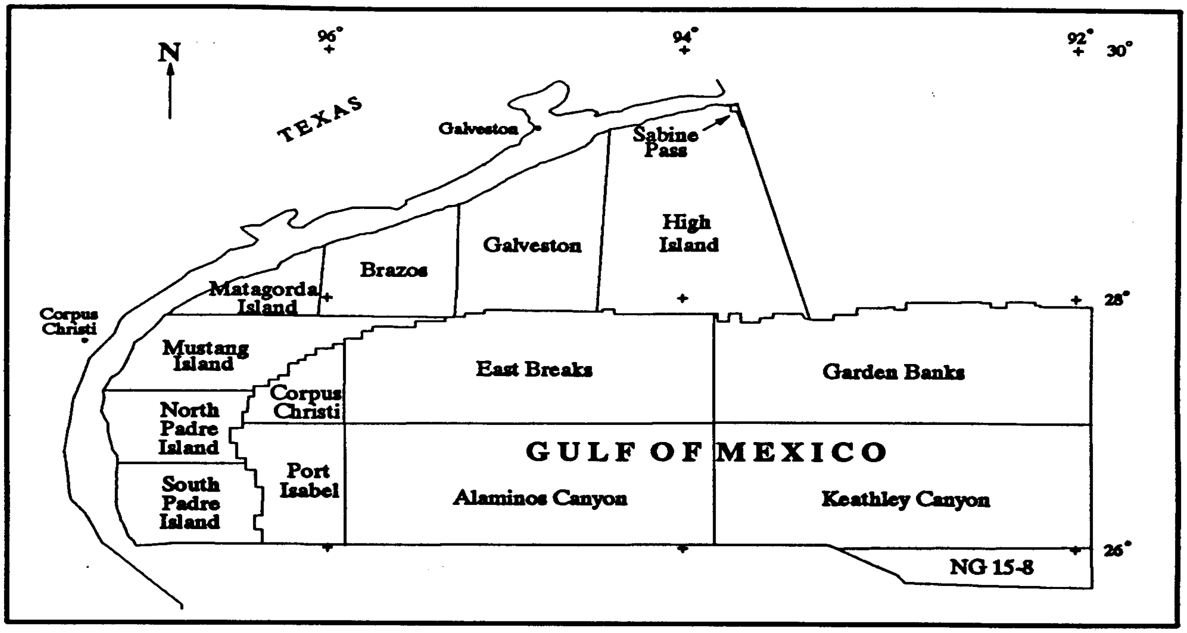



Figure 4D- 2. Map of Central Gulf of Mexico Planning Area

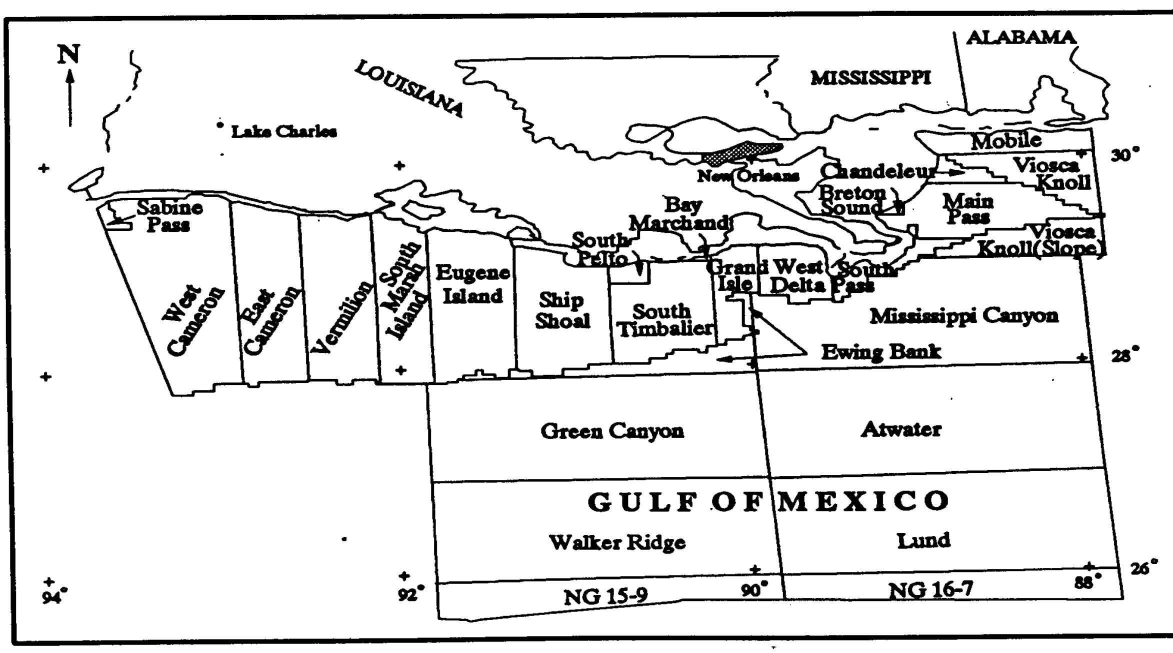
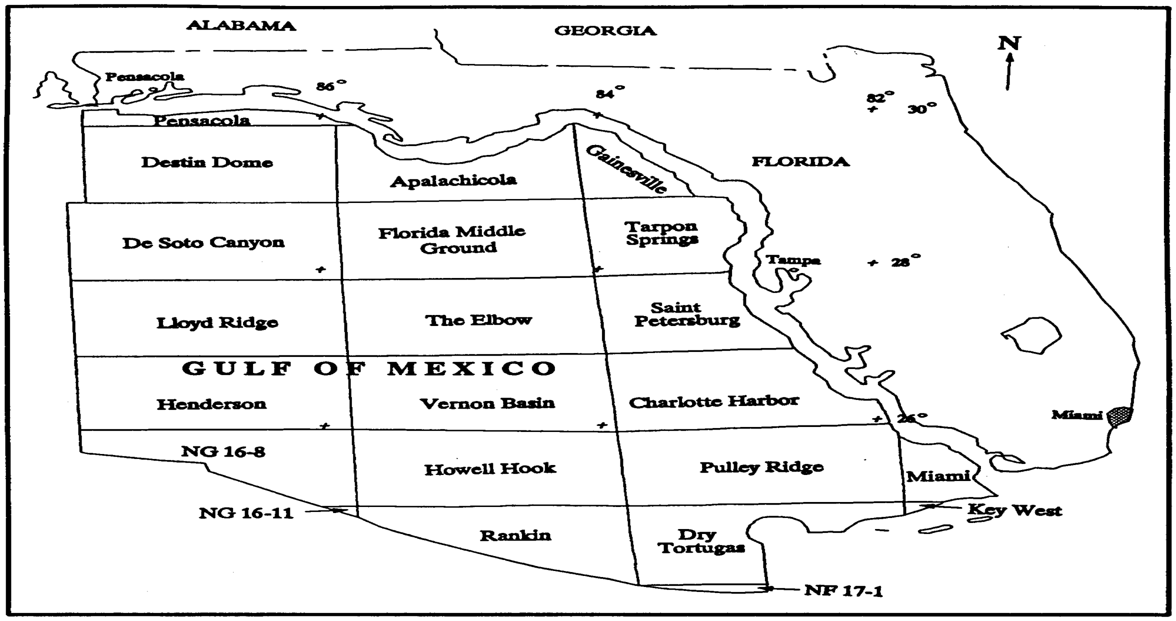


**Figure 4D-3. Map of Eastern Gulf of Mexico Planning Area**




***Endogenous Component.*** After the exogenous price/supply curves have been developed, they are transmitted to and manipulated by an endogenous program within OGSM. The endogenous program contains the methodology for determining the development and production schedule of the deepwater offshore Gulf of Mexico OCS oil and gas resources from the price/supply curves. The endogenous portion of the model also includes the capability to estimate the impact of penetration of advanced technology into exploration, drilling, platform, and operating costs as well as growth of reserves.

## *PROCESS FLOW DIAGRAMS*

The general process flow diagram for the exogenous component of DWOSS model is provided in Figure 4D-4. This component of the model is used to generate price-supply curves for use in the endogenous component of the model. The general process flow diagram for the endogenous component of DWOSS model is provided in Figure 4D-5. This component utilizes price information received endogenously from NEMS to generate reserve additions and production response based on the supply potential made available by the price-supply model.

## *CHARACTERIZATION OF THE DEEPWATER UNDISCOVERED RESOURCE*

Great bulk of undiscovered oil and gas reserves are estimated to be in deeper waters of the Gulf of Mexico OCS. Based on MMS estimates, approximately 12.94 billion of 25.39 billion barrels of oil-equivalent crude oil and natural gas resources are in deepwater areas of the Gulf of Mexico OCS, as shown below in Table 4D-1. The estimated distribution of the MMS resource between water depth ranges 200 - 400 meters and 400 - 900 meters is based on background information from MMS, and are ICF Kaiser's interpretation of this information relative to areal distributions of the Gulf of Mexico OCS area between these two water depth regions.

**Figure 4D-4. Programming Structure of the Exogenous Component of DWOSS**

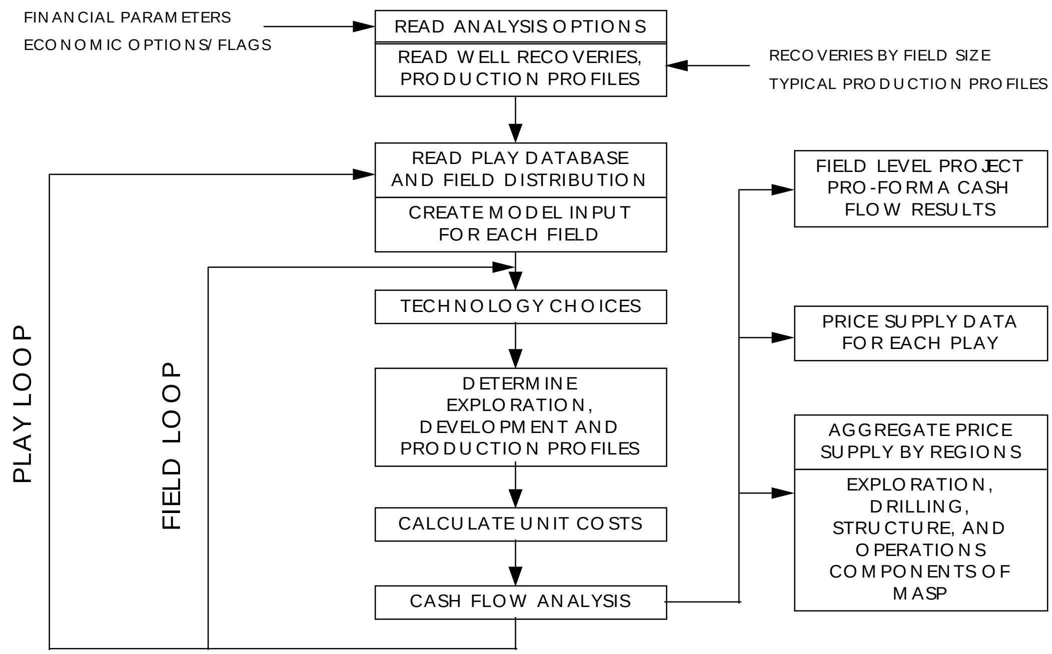


**Figure 4-5. Programming Structure of the Endogenous Component of DWOSS**

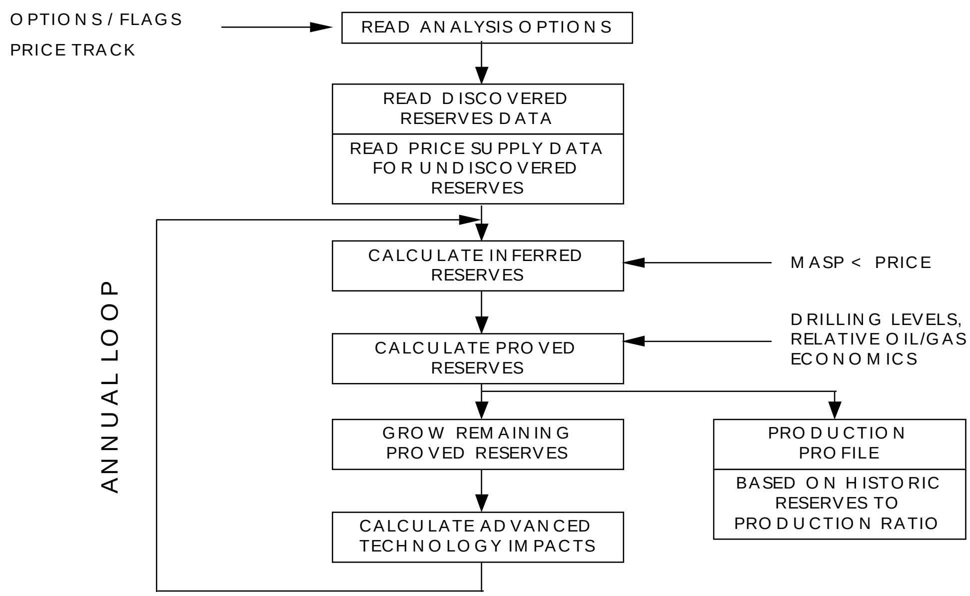


**Table 4D-1**
**Recoverable Undiscovered Reserves in the Deepwater Gulf of Mexico**
**(Billions of Barrels of Oil Equivalent)**

| **Water Depth Category** | **Western** | **Central** | **Eastern** | **Total** |
|---|---|---|---|---|
| 200 m - 400 meters | 0.311 | 0.593 | 0.045 | 0.949 |
| 400 m - 900 meters | 0.621 | 1.186 | 0.089 | 1.896 |
| > 900 meters | 4.449 | 5.148 | 0.500 | 10.097 |

A distribution of the fraction of resource that is leased vis-a-vis the amount that remains to be leased was also obtained from MMS. The fraction of the resource that is leased is given below:

**Estimated Fraction of Discovered Resource Leased**
**in the Gulf of Mexico**

| **Western** | **Central** | **Eastern** | **Total** |
|---|---|---|---|
| 0.13 | 0.18 | 0.01 | 0.14 |

### *Database of Undiscovered Oil and Gas Prospects*

For the purposes of creating resource inputs for the DWOSS, the undiscovered oil and gas prospects in the deepwater Gulf were assumed to be distributed into the ten (10) "plays" listed in Table 4D-2 for each of the three Gulf of Mexico regions. These plays are closely tied to the MMS categorization of the undiscovered resource base in the Gulf, but have been enhanced to divide the MMS "water depth aggregation plays" in the water depth range 200 - 900 meters into two plays aggregated by water depth ranges 200 - 400 meters and 400 - 900 meters. This was done to maintain consistency with the classification of water depth ranges in DWOSS, and to account for different royalty relief opportunities available based on water depth.

The resource distribution information received from MMS consisted of two sets of databases. The first listed typical recoveries for crude oil and natural gas, typical gas-oil-ratio for oil fields and typical condensate yield for gas fields, and the proportion of oil and gas bearing fields. The other database listed a rank-ordered field size distribution (in acre-ft) in each play. The parameters listed in the first database are:

1. Proportion gas bearing fields, fraction,
2. Oil recovery factor, Bbl/Acre-ft,
3. Gas-oil ratio for oil bearing fields, Scf/Bbl,
4. Gas recovery factor, Mcf/Acre-ft, and
5. Condensate yield for gas bearing fields, Bbl/MMcf.

**Table 4D-2**

**List of Deepwater Gulf of Mexico Plays in DWOSS**

| Region | Play Code | Description of the Play |
|---|---|---|
| WGOM | UGWG0301 | Western Gulf of Mexico, Water Depth Aggregation Range 200-400 meters |
| | UGWG0302 | Western Gulf of Mexico, Water Depth Aggregation Range 400-900 meters |
| | UGWG0401 | Western Gulf of Mexico, Water Depth Aggregation Range > 900 meters |
| | UGTE0103 | Gulf of Mexico Tertiary Basin, Perdido Fold Belt Play |
| CGOM | UGCG0301 | Central Gulf of Mexico, Water Depth Aggregation Range 200-400 meters |
| | UGCG0302 | Central Gulf of Mexico, Water Depth Aggregation, WD Range 400-900 meters |
| | UGCG0401 | Central Gulf of Mexico, Water Depth Aggregation Range > 900 meters |
| EGOM | UBLK0110 | GOM Atlantic, Lower Cretaceous, Carbonate Complex, Water Depth < 900 meters |
| | UBLK0120 | GOM Atlantic, Lower Cretaceous, Carbonate Complex, Water Depth > 900 meters |
| | UGEG0401 | Eastern Gulf of Mexico, Water Depth Aggregation Range > 900 meters |

However no information was available from these databases on the distribution between oil and gas fields. Therefore, using spreadsheet analyses, different combinations of oil and gas fields in each play were assumed until close matches were obtained for the following with the corresponding MMS values:

- Proportion gas bearing fields (number of gas fields / total number of fields in the given play); and
- Total oil and gas resource for each water depth range in each region

Once the distribution of oil and gas bearing fields for each play was established, the resource database comprising of the field rank, field type (oil or gas), field size (oil and associated gas, or gas and associated condensate) was combined with other field properties and parameters necessary for generating the required inputs for the DWOSS to generate play-specific input database sets.

### *Additional Required Input Data*

Additional information that is needed to perform the economic evaluation of offshore deepwater crude oil and natural gas fields include the following:

- The Average API Gravity is used to compute a price penalty based on the quality of crude oil. These data have been obtained from published averages in the Gulf of Mexico, as well as MMS estimates.
- The Average Gas-Oil Ratio is used to determine the total amount of associated/dissolved (A/D) gas in the oil field.
- The Average Condensate Yield is used to determine the total amount of associated condensate in the gas field.
- The Average Water Depth is used for platform and well cost calculations. Average water depth for each water depth class was determined from actual field data in different water depth categories of the Gulf of Mexico.
- The Total Exploration and Development Well Drilled Depths are critical factors in drilling

costing algorithms. The depths reflect the most likely future exploration and development well depths in each play and were based on actual well completion data.

- O <u>Exploration and Development Drilling Success Rates</u> are critical in determining the number of well required to explore for and develop a field.

## *DEEPWATER TECHNOLOGY OPTIONS*

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. Some of the reasons behind this are that the deepwater prospects:

- O Are in a predominantly frontier exploration area;
- O Are in locations that are more remote;
- O Have wells that produce at much higher rates; and
- O Are explored for and developed in significantly more extreme environmental conditions.

This section sets forth the technology choices for exploration, development and production of the Gulf of Mexico deepwater offshore fields. The choices are consistent with current practices as well as projected technology choices for fields which are slated to be developed in the near future.

In many situations in the deep water OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. For purposes of specifying technology choices in DWOSS, a standard classification system for categorizing fields by size class was required.

The table below shows the distribution of field sizes by classes defined by US Geological Survey (USGS), which are used for specifying many of the technology assumptions in DWOSS.

| **USGS Class** | **Field Size Range (MMBOE)** |
|---|---|
| 7 | 0.190 - 0.380 |
| 8 | 0.380 - 0.760 |
| 9 | 0.760 - 1.520 |
| 10 | 1.520 - 3.040 |
| 11 | 3.040 - 6.070 |
| 12 | 6.070 - 12.140 |
| 13 | 12.140 - 24.300 |
| 14 | 24.300 - 48.600 |
| 15 | 48.600 - 97.200 |
| 16 | 97.200 - 194.300 |
| 17 | 194.300 - 388.600 |
| 18 | 388.600 - 777.200 |
| 19 | 777.200 - 1554.500 |
| 20 | < 1554.500 |

### *Technology Choices for 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. For deepwater exploratory drilling, two types of drilling rigs are most commonly employed.

**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.

**Dynamically positioned drill ships** are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3000 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.

Water depth is the primary criterion for selecting a drilling rig. Therefore, DWOSS assumes the selection of drilling rig type to be a function of water depth, as follows:

| **Drilling Rig Type** | **Water Depth (meters)** |
|---|---|
| Semi-submersible | 200 - 900 |
| Drillship | > 900 |

### *Technology Options for Development/Production Structure*

Six different options for development/production of deepwater offshore prospects are currently assumed in DWOSS, based on those currently considered and/or employed by deepwater 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.

1. **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.

2. **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.
3. **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 three years.

4. **Floating Production System (FPS).** The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10%. These structures can only accommodate a maximum of 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.

5. **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 catenary system of six to twenty 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.

6. **Subsea Wells System.** Subseas system ranges 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 sub-sea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet.

The typical water depth and field size class ranges for selection of a given platform in the model is given below:

| **Production Structure** | **Water Depth (meters)** | | | **Field Size Class Range** |
|---|---|---|---|---|
| Fixed Platform | | < | 400 | > 12 |
| Compliant Tower | 400 | - | 600 | > 15 |
| Tension Leg Platform | 600 | - | 1500 | > 15 |
| Floating Production System | 400 | - | 1500 | 12 - 15 |
| Spar Platform | | > | 1500 | > 12 |
| Subsea Wells System | All Depth Ranges | | | < 12 |

### *Technology Choices For 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.

### *Technology Choices for Product 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.

## *EXPLORATION, DEVELOPMENT AND PRODUCTION SCHEDULING*

This section sets forth the descriptions, assumptions, methodology, and sources used for determining the exploration, development, and production schedules assumed for various types of potential prospects that remain to be discovered in the deepwater offshore Gulf of Mexico.

The typical project development in deepwater offshore consists of the following phases. 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
  - Exploration drilling program
  - Delineation drilling program
- Development phase
  - Fabrication and installation of the development/production platform
  - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
  - Construction of gathering system
- Production operations
- Field abandonment.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

### *Exploration Phase*

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

**Exploration drilling.** Drilling of all exploration wells (i.e., the wildcat and all corresponding exploratory dry holes) is assumed to begin in the first year of the field development project, and that exploration drilling takes one year to complete. The e***xploration 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 be drilled to discover the field. For all deepwater Gulf of Mexico OCS prospects, DWOSS assumes that the exploration success rate is 1:4, i.e., for each successful well, a total of four wells need to be drilled.

**Delineation drilling.** The delineation well drilling program is assumed to begin the year after initiation of exploration drilling, i.e., year 2 of the project. The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. In the engineering costing model and for production operations, the delineation wells are treated as dry holes. The number of delineation wells required to define each field is calculated using the ***combined extension and development success rate*** (ratio of successful extension and development wells to total extension and development wells). The duration of the delineation well drilling program is determined as a function of the number of delineation drilling wells, the average total drilled depth, and the average drilling rate. The equations for drilling rates used in the model are shown below for various depth categories:

| Total Drilled Depth (feet) | | Average Drilling Rate (feet/day) |
|---|---|---|
| < | 10,000 | 800 - 0.058 * Drilling Depth |
| ≥ | 10,000 | 200 |

These relationships were developed based on an examination of drilling rates currently occurring in the deepwater Gulf of Mexico.

### *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 table below lists the required time for construction and installation of the various development structures used in the model. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

**<u>Large fields (Field Size Class > 15)</u>**

| Water Depth | Construction and Installation Time (Years) | | | |
|---|---|---|---|---|
| (meters) | Fixed Platforms | Compliant Towers | Tension Leg Platforms | Spar Platforms |
| 0 - 400 | 2 | - | - | - |
| 400 - 900 | - | 3 | 3 | - |
| > 900 | - | - | 4 | 3 |

**<u>Mid-size fields (Field Size Class 12 - 15)</u>**

| | Fixed Platforms | Floating Production Systems |
|---|---|---|
| 0 - 400 | 2 | - |
| > 400 | - | 2 |

**<u>Small fields (Field Size Class < 12)</u>**

**Tied back to existing production facilities through subsea manifold and pipelines.**

1 year

The importance of reducing the time lag is addressed by assuming the use of early production techniques, such as:

- Using simultaneous drilling and production operations
- Pre-drilling some of the development wells during the time in which the development structure is being constructed and installed.

**Development drilling program.** The timing of the development drilling program is also determined by the type of development system assumed. When conventional fixed platforms are used, the following development schedule is assumed.

- No pre-drilling program is utilized. Use of a fixed platform would delay initial production by two to four years, which is consistent with current offshore practices.
- The development drilling program begins the year after the platforms are installed. All wells are drilled from the platform.

For all other types of development structures, including compliant towers, tension leg platforms, Spar platforms, and floating production systems, the following development schedule is assumed:

- The subsea drilling templates are fabricated and installed the first year of structure construction.
- Pre-drilling of some development wells begins from a mobile rig during the first year of structure construction, and continues through the construction time.
- The remaining wells are drilled from the structure beginning the year after installation.
- The pre-drilled wells begin producing during the first year after installation of the structure.

Regardless of the type of development system used, the number of development wells required to completely develop the field is determined by the field size and estimated ultimate recovery per well. The ***Development Success Rate*** (ratio of successful to total developmental wells) is used to establish the number of unsuccessful wells that can be expected while drilling within the boundary of a known field. These development drilling success rates are based on historical drilling data.

The time required to drill all wells, both successful and dry, depends on the number of wells to be drilled, the average drilled depth and a corresponding average drilling rate:

| Total Drilled Depth (feet) | | Average Drilling Rate (feet/day) |
|---|---|---|
| < | 10,000 | 1000 - 0.0725 * Drilling Depth |
| ≥ | 10,000 | 250 |

These relationships are based on examination of drilling rates currently occurring in the deepwater Gulf of Mexico. It is assumed that 15 days are required to complete each well, after drilling is complete. Further, an equal number of wells are assumed to be drilled each year.

**Production transportation/ gathering system.** It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within one year.

### *Production Operations*

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. The well productivities and production profiles over the productive life are discussed below.

**Typical production profiles.** Typical oil and gas production profiles for offshore development wells are based upon typical recovery profiles generated by using standard reservoir performance models. The Primary Recovery Predictive Model (PRPM) for crude oil and Gas Systems Analysis Model (GSAM) for natural gas, developed for Department of Energy's Office of Fossil Energy, were used for this purpose. These models can predict the deliverability of the reservoir and year-wise production performance as a function of reservoir properties (area, thickness, porosity, permeability, lithology, depth, saturation etc.) and technology, using standard stream tube (for crude oil) and type curve (for natural gas) performance prediction techniques. The associated gas recovery in case of an oil well and the associated NGL (natural gas liquids) in case of a gas well are calculated using a regional average gas-oil ratios. The production profiles generated using the reservoir performance models were modified to reflect the platform capacity constraints, as well as wellbore productivity constraints not considered in the performance models. In order to generate the revised per well production profiles, the producing life of each well is assumed to be five years for a small field, ten years for a mid-size field, and fifteen years for a large field. The revised per well production profiles assumed in DWOSS are given below:

| Year in Production | Percent of Total Ultimate Recovery FIELD SIZE CLASS RANGE | | |
|---|---|---|---|
| | 4 - 9 | 10 - 14 | 15 - 20 |
| 1 | 40.0 | 30.0 | 27.0 |
| 2 | 26.0 | 22.0 | 21.0 |
| 3 | 17.0 | 16.0 | 16.0 |
| 4 | 11.0 | 12.0 | 11.0 |
| 5 | 7.0 | 9.0 | 8.0 |
| 6 | | 7.0 | 6.0 |
| 7 | | 5.0 | 4.0 |
| 8 | | | 3.0 |
| 9 | | | 3.0 |
| 10 | | | 2.0 |

**Productivity and number of wells.** The number of producing oil / gas wells per field is a key input required by DWOSS. For a particular field, the number of required wells is determined by using an average well productivity (arrived at by summation of the annual production figures generated by the reservoir performance models, PRPM and GSAM) as a function of field size class, divided into the field size to give the required number of wells for the particular size field. The data used for estimating recovery per well as a function of field size in DWOSS are shown in Table 4D-3.

**Table 4D-3**

**Average Size of a USGS Field Size Class, and Per Well Recovery**

| USGS Class | Average Size (MMBOE) | Per Well Recovery (MBOE) |
|---|---|---|
| 7 | 0.273 | 250.0 |
| 8 | 0.547 | 500.0 |
| 9 | 1.094 | 1000.0 |
| 10 | 2.189 | 1500.0 |
| 11 | 4.378 | 2000.0 |
| 12 | 8.741 | 2600.0 |
| 13 | 17.480 | 3300.0 |
| 14 | 34.990 | 4300.0 |
| 15 | 69.980 | 5500.0 |
| 16 | 139.960 | 6800.0 |
| 17 | 279.790 | 8500.0 |
| 18 | 559.580 | 10500.0 |
| 19 | 1119.160 | 13500.0 |

**Notes:**

1. Geometric means of USGS Field Size Classes ( = 1.44 * minimum of the range).
2. 1 BOE = 5.7 Mcf

### *Abandonment Phase*

The year when the project production reaches economic limit (operating costs exceed the revenues), defines the last year of production. The development structures and production facilities are abandoned in the year following the cessation of production.

## *ENGINEERING COSTING ALGORITHMS*

This section sets forth descriptions, assumptions, methodology, and reference sources used for determining the engineering cost algorithms for key cost factors for developing and producing crude oil from the deepwater Gulf of Mexico. The assumptions underlying the selection of technologies for field exploration, development, and production represent the best industry practices subject to the ultimate project economics, and are based on review of a number of sources including a database of existing/proposed deepwater projects, past analytical works and reports of ICF, MMS costing assumptions, and various other sources. The cost equations represent the functional relationships between the cost components of the financial analysis model and the parameters affecting them.

### *Capital Costs*

**Geological and Geophysical Activities.** The cost to conduct the geological and geophysical (G&G) assessment of the field is based on surveys of oil and gas industry expenditures. The cost of these activities tends to be roughly 15 percent of the cost to drill and complete all exploration wells, including the field delineation wells. In financial analyses, the portion of these costs associated with drilling the unsuccessful wells (dry holes) is expensed in the year incurred (the first year of analysis), while the portion of the costs associated with drilling successful wells is depleted using unit-of-production depreciation. However, since most offshore exploration and delineation wells are plugged after drilling, all costs of all such wells are assume to be expensed in DWOSS.

**Exploration and Delineation Well Drilling.** The costs to drill an offshore exploration well can be divided into the following three categories:

1 Fixed cost items - including wellhead and downhole equipment, and rig setup

2 Time dependent items - including rigs, barges, labor, service equipment rentals, and other support services

3 Well depth dependent items - including casing, tubing, cementing, and other equipment associated with drilling the well.

Exploration drilling costs estimated in the model for the two classes of drilling rigs are presented below:

<u>Semi-Submersible Rigs ($/well)</u>

Exploration Drilling Cost = 2,000,000 + 1,825*WD + (0.01*WD + 0.045*ED - 415)*ED

<u>Dynamically-Positioned Drill Ships ($/well)</u>

Exploration Drilling Cost = 8,000,000 + 175*WD + (0.0525*ED - 600)*ED

where,

| | | |
|---|---|---|
| WD | = | Water Depth (feet) |
| ED | = | Exploration Drilling Depth (feet) |

The engineering costing equations used for estimating exploration well drilling costs are also used to estimate the cost to drill field delineation wells (i.e., the wells drilled to define the extent of the field). The delineation wells are treated as dry exploration wells.

Delineation Drilling Cost = 0.85*Exploration Drilling Cost

All costs associated with drilling the exploration wells are treated as intangible capital investments and are expensed in the year in which they occur.

**Production and Development Structure.** The type of development structure depends primarily upon the conditions of water depth, environmental hostility, and reservoir size. In some cases, the development structures used for drilling production and injection wells also serve as the production facility.

The total cost of the development structures is distributed evenly over the time period between the initiation of construction and the installation of the structures. In each year during this development period, 90% of these costs are treated as capitalized tangible investments and are depreciated beginning the following year. The remaining 10% of these costs are expensed in the year incurred. The costs associated with each type of development and production structure considered in DWOSS are described in the paragraphs below. In all the equations for the various platforms shown in the paragraphs below:

NSLT = Number of Slots per Structure
WD = Water depth (feet)
NTMP = Number of Templates

1 **Conventional Fixed Platform (FP).** The following engineering costing equations are used to estimate conventional fixed platform costs, which include design, fabrication, and installation of the jacket, pilings, and the deck sections, as shown below:

Cost ($) = 2,000,000 + 9,000*NSLT + 1,500*WD*NSLT + 40*WD*WD

**2** **Compliant Tower (CT).** The costing equation developed for compliant towers is expressed as a function of water depth and is valid for water depths greater than 1,000 feet. Costs include those for the design, fabrication, and installation of the jacket, pilings, deck sections, and mooring system (including guy lines), as shown below:

Cost ($) = (NSLT + 30)*(1,500,000 + 2,000*(WD-1,000))

3 **Tension Leg Platform (TLP).** Tension leg platforms are designed primarily for use in deeper waters; however, the costs are relatively insensitive to water depths greater than 1,000 feet. The following costing equation includes the design, fabrication, and installation of the deck sections, mooring system, and related foundations, as shown below:

Cost ($) = (NSLT + 30)*(3,000,000 + 750*(WD-1,000))

4 **Spar Platform (SPAR).** Spar platforms are a recent development. It is estimated that these types of platforms would be dominant in the deepwater, and that they would be applicable in water depths upto 10,000 feet. The costs are shown below:

Cost ($) = (NSLT + 20)*(5,000,000 + 500*(WD-1,000))

5 **Floating Production System (FPS).** The costs to construct a FPS include not only the rig purchase, fabrication, and installation costs, but also the cost to fabricate and install a flexible production riser system, and are expressed by the following equation. Since flexible production risers are generally easier to install and maintain than rigid risers, DWOSS assumes that production to a converted semi-submersible or tanker is accomplished with flexible risers. The costs are shown below:

Cost ($) = (NSLT + 20)*(1,500,000 + 250*(WD-1,000))

6 **Subsea Wells System.** Since the cost to complete a well are included in the development well drilling and completion costs, DWOSS assumes no cost for a subsea wells system. Typically subsea wells are tied back to neighboring structures, and the only cost is the cost of the pipeline to connect the wells from the subsea system to the platform.

**Subsea Template Installation.** The engineering costing model also assumes that a subsea template is required for all development wells producing to any structure other than a fixed platform.

Cost of Subsea Template ($/well) = 2,500,000 * NTMP

These costs are also applicable to the subsea well systems tied back to neighboring platforms.

**Development Well Drilling.** During the field development phase of an offshore project, the type of structure used to drill the development wells also depends on both economic and technical criteria. The most important factors affecting the selection of a drilling structure are the timing of the field development and the type of production facility employed.

In all cases except a field where a fixed platform is assumed to be installed, DWOSS assumes that pre-drilling of development wells will be carried out using the exploration drilling rig. It is assumed that wells will be drilled from either a semi-submersible rig or a dynamically-positioned drill-ship. DWOSS assumes that the cost to pre-drill a dry development well would be equal to the cost of drilling a delineation well using one of the rigs listed above. For a successful development well, the costs for completing and equipping the well are added to the cost of drilling a dry development well.

DWOSS further assumes that once the production structure is ready, the remaining development wells will be drilled from the platform. The components of the engineering costing equations for development drilling are similar to those presented earlier for exploration drilling, except for the following differences:

- O The average time required to drill and complete a development well is much less than for an exploration well.
- O The drilling rig rates are much less for wells drilled from a platform or tower.

The dry development well drilling costs do not include costs to complete and equip the well (production casing or production facility costs, i.e., flowlines, valves, etc.). DWOSS is set up to compute the dry development drilling well costs and well completion and equipment costs. The cost of successful development drilling is calculated by summing the dry development well drilling costs and the well completion and equipment costs.

<u>Dry Development Drilling Cost</u>

For water depths less than or equal to 900 meters,

Cost ($/well) = 1,500,000 + (1,500 +0.04*DD)*WD + (0.035*DD - 300)*DD

For water depths greater than 900 meters,

Cost ($/well) = 5,500,000 + (150 + 0.004*DD)*WD + (0.035*DD - 250)*DD

where,

| | | |
|---|---|---|
| WD | = | Water Depth, feet |
| DD | = | Development Drilling Depth, feet |

Well Completion and Equipment Cost ($/well)

| **Water Depth (feet)** | **Development Drilling Depth (feet) < 10,000** | **10,001-20,000** | **> 20,000** |
|---|---|---|---|
| 0 - 3000 | 800,000 | 2,100,000 | 3,300,000 |
| > 3000 | 1,900,000 | 2,700,000 | 3,300,000 |

In the engineering costing model, 70% of the costs associated with drilling development wells are treated as intangible capital investments, while the remaining 30% of the costs are considered to be tangible investments, which are capitalized and depreciated over a 10 year life. In addition, 30% of the intangible costs are capitalized beginning the year after they are incurred. Remaining 70% of the intangible costs are expensed in the year in which they occur.

**Production Facility System.** The cost to install production equipment on the development structure is a function of the anticipated peak oil / gas production capacity for the structure. The following equations for estimating facility costs include primary separation facilities, treating equipment, pumps, compressors, storage systems, and associated piping and control systems:

**For Oil Production**

Oil Production Capacity: 0 - 10,000 bbl/day

Production Equipment Cost ($/well) = (540,000 +52.5*QMXOIL) / NSTRUC

Oil Production capacity: > 10,000 bbl/day

Production Equipment Cost ($/well) = (900,000 + 7.8*QMXOIL) / NSTRUC

**For Gas Production**

Gas Production Capacity, 0 - 20 MMcf/day

PRCEQP = (0.675 * QMXGAS) * 1,000,000 / NSTRUC
TOPEQP = (0.950 * QMXGAS) * 1,000,000 / NSTRUC

Gas Production Capacity, 20 - 40 MMcf/day

PRCEQP = (13.5 + (0.275 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (19.0 + (0.225 * (QMXGAS-20)) * 1,000,000 / NSTRUC

Gas Production Capacity, 40 - 120 MMcf/day

PRCEQP = (19.0 + (0.181 * (QMXGAS-40)) * 1,000,000 / NSTRUC
TOPEQP = (23.5 + (0.100 * (QMXGAS-40)) * 1,000,000 / NSTRUC

Gas Production Capacity, > 120 MMcf/day

PRCEQP = (33.5 + (0.156 * (QMXGAS-20)) * 1,000,000 / NSTRUC
TOPEQP = (31.5) * 1,000,000 / NSTRUC

where,

| | | |
|---|---|---|
| NSTRUC | = | Number of Structures |
| PRCEQP | = | Processing Equipment Cost |
| TOPEQP | = | Topside Equipment Cost |
| QMXOIL | = | Peak Oil Production Capacity, bbl/day |
| QMXGAS | = | Peak Gas Production Capacity, Mmcf/day |

For platforms producing primarily gas, the top total costs of the topside facility is represented by the sum of the processing equipment costs (PRC EQP) and the topisde equipment cost (TOPEQP).

The production facility costs are assumed to occur in the same year in which the development structure is constructed. All of the production and injection equipment costs are treated as tangible investments and are depreciated beginning the following year after costs are incurred.

**Production Gathering System.** All fields are assumed to utilize existing trunk lines in the vicinity of the field. Each development structure requires a gathering system. The average length of each gathering system in the different fields are assumed to be a function of the size of the field. The following approximations for pipeline costs were developed.

For all small fields (Field Size Class < 10), GATDIS = 1 mile

For all large fields (Field Size Class > 15), GATDIS = Data from Input Database

For all mid-size fields (Field Size Class Range 10-15), GATDIS is determined by interpolating between the values for the small and large fields.

DWOSS estimates the cost of constructing gathering system as follows:

Gathering Line Costs ($) = 250,000 * GATDIS * NSTRUC

where,

GATDIS = Average length of gathering system
NSTRUC = Number of structures in the field

These costs are considered to be tangible capital investments and are capitalized the year following the installation costs are incurred.

**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 follow:

| | 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 |

There is a provision in the model to not include the abandonment costs in the economic evaluation of the deepowater Gulf of Mexico OCS prospects. It is a user-defined analysis option.

### *Annual Operating Costs*

**Platform Operating Costs.** In general, platform operating costs for all types of structures are a function of water depth and the number of slots on the structure. These costs include the following items:

- O primary oil and gas production costs
- O labor
- O communications and safety equipment
- O supplies and catering services
- O routine process and structural maintenance
- O well service and workovers
- O insurance on facilities
- O transportation of personnel and supplies.

The equation used for estimating annual structure operating costs is as follows:

Cost (\$/structure/year) = 1,265,000 +135,000*NSLT + 0.0588*NSLT*WD*WD

If water depth is less than or equal to 1500 feet, WD = WDEP
If water depth is greater than 1500 feet, WD = 1500

where,

| | | |
|---|---|---|
| WDEP | = | Water depth, feet |
| NSLT | = | Number of Slots per Structure |
| QGAS | = | Gas Production Capacity |
| NSTRUC | = | Number of Structures |

**Operating Costs of Pipeline Operating System.** Pipeline operating costs are estimated to be a function of the amount of oil and gas produced. The input database file for each of the water depth aggregated plays contains the typical transportation tariffs (in \$/bbl of crude oil or \$/Mcf of gas produced) for these regions and is used in the calculation of pipeline operating costs. These costs represent a share of the operation of the existing trunk line that is proportional to the volume of oil and gas transported through the trunk line by the prospect under consideration.

## *FINANCIAL ANALYSIS AND PRICE-SUPPLY MODELING*

The financial analysis and price-supply model is the off-line exogenous component of DWOSS. It consists of a set of algorithms that have been designed to systematically evaluate the relative economic potential of the undiscovered crude oil and natural gas prospects in the deepwater Gulf of Mexico OCS. Key reasons for the necessity of a systematic financial analysis approach are:

- To represent all standard industry accounting practices in determining the after-tax cash flow for each year of a potential project, including depreciation and expensing;
- To systematically represent all issues associated with prospect-specific resource characteristics, technology choices, project scheduling, and costing ;
- To represent all components that are dependent on price, such as transportation tariff deductions and API gravity adjustments;
- To represent all transfer payments, such as taxes and royalties, including government incentives
- To represent the time value of money; and
- To solve for the replacement cost, or that value which yields a zero net present value of the combined yearly after-cash flow streams.

The financial analysis algorithms in DWOSS is a minimum supply price calculation routine that uses the method of bisection to solve for the minimum required crude oil or natural gas price for a crude oil or natural gas prospect, respectively, to be economic at a specified rate of return. A discounted cash flow (DCF) calculation is used to estimate the present net worth of the net inflow or outflow of money that occurs during a specified period, as represented below:

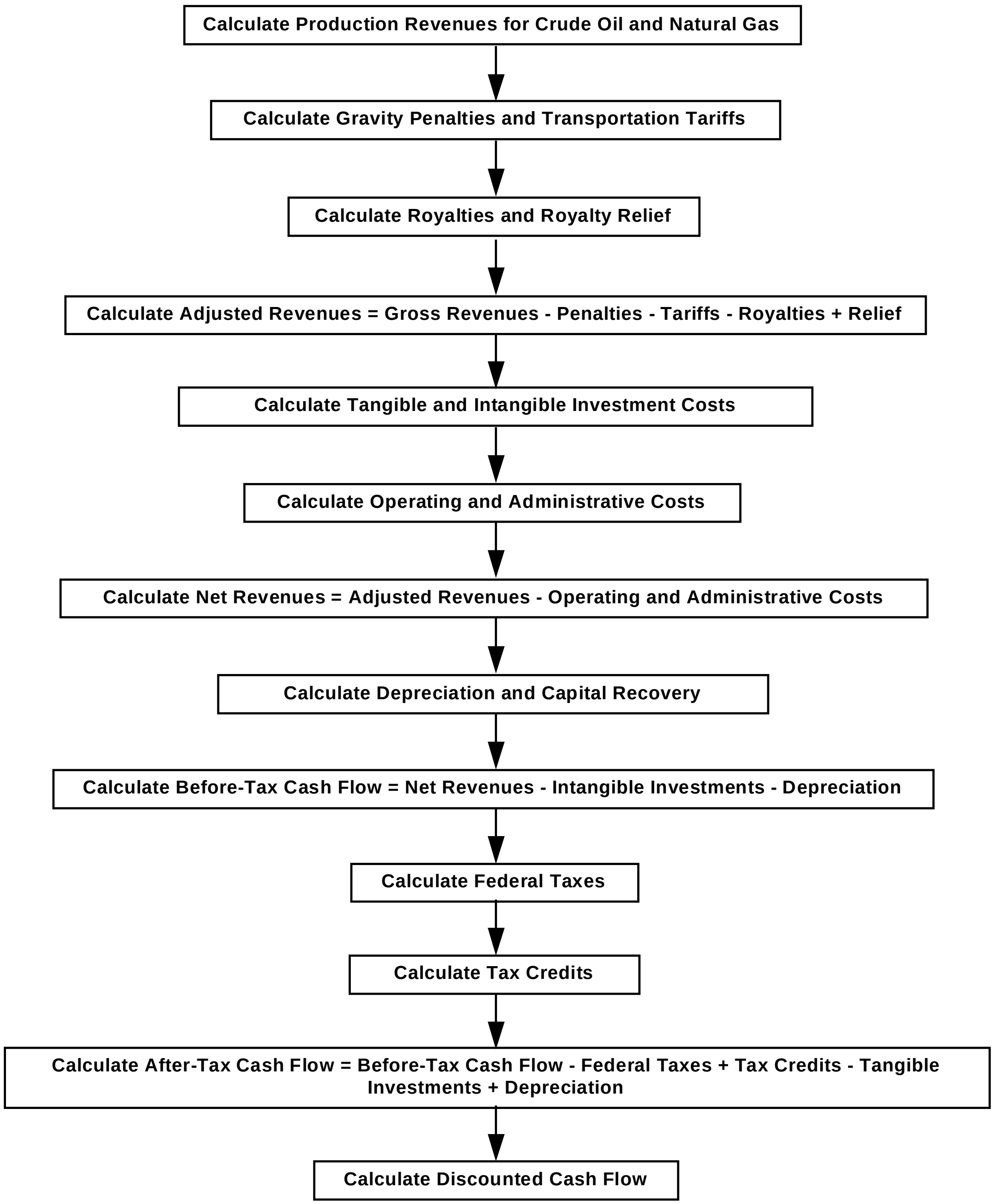
| | |
|---|---|
| | **Gross Revenue or Savings** |
| less | **Operating Expenses** |
| less | **Tax Costs** |
| less | **Capital Costs** |
| = | **Cash Flow** |

Figure 4D-6 represents the process-flow diagram of the financial analysis routines in DWOSS. In the following sections, the key components and their methodologies are described in more detail.

### Gravity Adjusted Revenues

The 1984 National Petroleum Council (NPC) assessment of the potential of enhanced oil recovery (EOR) devoted considerable attention to the value of crude oils of various composition. In general, low API gravity oils (10-26$^{o}$ API) have less value because of a preponderance of heavy hydrocarbons (and perhaps sulfur) which reduces the volume of higher value refined products. In addition, special facilities (and higher costs) are required to transport and refine heavier crudes. Although the pricing of crude oil is

**Figure 4D- 6. Process Flow Diagram of the Discounted Cash Flow Financial Analysis**



a complex and intricate process, the NPC EOR study was able to make the following simplifications, which have been adapted for use in DWOSS as shown below:

- The reference standard for crude oil is 40$^{o}$ API.
- If the typical crude gravity for a field is at or above 32$^{o}$ API, the price penalty is \$0.10 per degree below 40$^{o}$ API.
- If the typical crude gravity for a field is between 20$^{o}$ and 31$^{o}$ API, the price penalty is \$0.20 per degree below 40$^{o}$ API.
- If the typical crude gravity for a field is below 20$^{o}$ API, the price penalty is \$0.40 per degree below 40$^{o}$ API.

These penalties are calculated from a nominal price of \$26.50 and are escalated for prices above or below this price.

**Co-product Valuation**

In order to determine the value of associated/dissolved gas produced from oil-bearing fields, and the value of condensate yield from gas-bearing fields in the deepwater Gulf of Mexico OCS, a co-product valuation methodology was incorporated into DWOSS. This assumes that the value of natural gas would be 68% of the energy-equivalent value of crude oil at the nominal oil price established from recent trends in valuations of crude oil and natural gas in the market. This value is used for all calculations of revenues from associated/dissolved gas in oil-bearing fields and condensate yield in gas-bearing fields.

**Capitalized and Expensed Costs**

Capital investments in DWOSS include expenditures for geological and geophysical evaluations, exploration drilling, delineation drilling, development drilling including pre-drilling, production structure, and gathering pipeline system.

For tax purposes, the fastest method of deducting costs is to “expense” them in the year incurred, which means to deduct them in full amount in the year incurred. However, tax law does not permit “expensing” all costs, but instead permits these costs to be “capitalized” and deducted for tax purposes over a period of time greater than a year.

***Pre-Development Costs*** which include geological and geophysical costs are depleted using “unit of production” depreciation method described in the following section.

***Exploration and Delineation Drilling Costs*** are treated as “intangible” investments and are expensed in the year incurred.

***Development Drilling Costs*** are split into tangible and intangible investment costs. In DWOSS, 30% of the costs are considered tangible investment costs. Intangible drilling costs are defined as the cost of drilling oil and gas wells to the point of completion. The model assumes that only 70% of the intangible drilling costs may be expensed in the year incurred with the remaining 30% of the intangible drilling costs “capitalized”.

***Production Structure Installation Costs***, like drilling costs, are split into tangible and intangible investments. The model assumes that only 10% of the intangible structure installation costs may be expensed in the year incurred and the remaining 10% intangible costs are “capitalized”.

***Operating Costs*** covering costs for direct labor, indirect labor, materials, parts and supplies used for operations are modeled as structure operating costs in DWOSS, and are expensed in the year they are incurred.

Capitalized items are depleted by depreciation in DWOSS. This permits the recovery of these expenditures over a specified period of time, as described in the following section.

**Depreciation Schedules Assumed**

Annual taxable income is reduced by an annual depreciation deduction or allowance that reduces the annual amount of income tax payable to justify “a reasonable allowance for the exhaustion, wear and tear, and obsolescence of property held by a tax payer for the production of income”. A property is depreciable if it meets these requirements:

- O It must be used in business or held for the production of income.
- O It must have a determinable life and that life must be longer than one year.
- O It must be something that wears out, decays, gets used up, becomes obsolete, or loses values from natural causes.
- O It is placed in service or is in a condition or state of readiness and available to be placed in service.

Depreciation of tangible property placed in service after 1986 is based on using modified accelerated cost recovery system (ACRS) depreciation for: (1) the applicable depreciation method, (2) the applicable recovery period (depreciation life), and (3) the applicable first year depreciation convention. Modified ACRS depreciation calculations relate to two of the following three depreciation methods modeled in DWOSS, ‘straight line depreciation’ and ‘double declining balance’. The third method, ‘unit of production’ depreciation, is used to a lesser extent for tax deduction purposes but to a greater extent for shareholder reporting purposes.

1. ***Straight Line Depreciation***. Straight line depreciation is the simplest method of computing depreciation. With the straight line method, depreciation per year is determined by multiplying the cost basis of a property times a straight line depreciation rate which is one divided by the allowable depreciation life, “n” years. In equation form:

   Straight Line Depreciation Per Year = (Cost) * (1/n)

2. ***Double Declining Balance.*** Double declining balance depreciation applies a depreciation rate to a declining balance each year. Using a standard approach, factors for each year in the depreciation life have been developed, as shown in equation below:

   Double Declining Balance Depreciation Per Year = (Cost) * (Adjusted Factor)

The adjusted factors for two depreciation lives in DWOSS, 5 years and 7 years, are given below:

| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| **Life = 7 years** | 0.14 | 0.25 | 0.20 | 0.16 | 0.13 | 0.08 | 0.04 |
| **Life = 5 years** | 0.15 | 0.22 | 0.21 | 0.21 | 0.21 | | |

3. ***Units of Production.*** Units of production depreciation deducts the asset cost over the estimated producing life of the asset by taking annual depreciation deductions equal to the product of the "asset cost" times the ratio of the "units produced" in a depreciation year, divided by "expected asset lifetime unit of production".

   Units of Production Depreciation Per Year = (Cost) * (Production in the Year)/ Total Recoverable Reserves in the Year

**Federal Tax, Royalties, and Incentives**

A rigorous methodology for computing federal taxes and producer royalties has been included in DWOSS. No provision has been kept for state taxes as these are not applicable in deepwater Gulf of Mexico OCS, which are exclusively federal properties. Provision has, however, been kept for calculation of severance taxes and tax incentives/credits, and have been set equal to zero for this analysis.

A federal tax rate of 34% on taxable income is assumed in the model. Royalty rates are set at 12.5% of the adjusted gross revenues. Royalty relief, as applicable under the new rules set forth by Minerals Management Service (MMS) for newly discovered fields, have been incorporated as follows:

| Water Depth Range | Relief Volume Applicable (MMBOE) |
|---|---|
| 200 - 400 meters | 17.5 |
| 400 - 900 meters | 52.5 |
| > 900 meters | 87.5 |

These figures set the limit on cumulative production of crude oil or natural gas that is not subject to royalty from a given field in each of the water depth classes. All production volumes in excess of these amounts are subject to royalty deductions.

**Discounted Net Present Value**

The term discount refers to the "present worth" in economic evaluation work. Compound interest is the generally accepted approach for calculating return on investment in time value of money calculations. The future value that is projected to be accrued from the investment of dollars today at a specified compound interest rate is equal to the sum of the accrued interest and the initial principal invested. The concept of "present worth" is just the opposite of compounding. The terms "discounting" implies reducing the value of something and is equivalent to determining the present worth of a future value. A discount rate of 10% is the default value assumed for all investment decisions in DWOSS, though this is a parameter that can be specified by the user.

**Net Present Value of After-Tax Cash Flow in year "IYR"**
$$= \quad \textbf{(After-Tax Cash Flow) / (1 + Discount Rate)}^{\textbf{(IYR - 1/2)}}$$

The previous sections covered the structure, methodology and key components of the exogenous portion of

DWOSS which is used to generate the price-supply curves for the deepwater offshore Gulf of Mexico OCS, i.e. the potential supply from undiscovered resources in deepwater Gulf at different nominal prices for crude oil and natural gas. These price-supply data can be generated under a variety of economic scenarios and analysis options due to the modular construction of the DWOSS. Having a separate exogenous component that can be used to study the impacts of various policy, regulatory and economic scenarios outside of the Oil and Gas Supply Module (OGSM) and National Energy Modeling System (NEMS) helps to speed the computational process. Besides supply price and reserves data, the exogenous component of DWOSS also transfers key cost data (exploration, drilling, structure installation, and operations) and well counts required to develop the reserves in a field.

## *DEVELOPMENT OF RESERVES AND PRODUCTION TIMING*

This is the endogenous component of DWOSS that is an integral part of OGSM. The primary purpose of this endogenous component is to make a realistic forecast of deepwater offshore Gulf of Mexico OCS reserves development and production performance over a study period of 15-20 years based on the information supplied to it, i.e., the price-supply and other supply-side information generated in the exogenous module, and price information for crude oil and natural gas generated from the other demand-side components of NEMS, the Petroleum Market Module (PMM) and Natural Gas Transmission and Distribution Module (NGTDM), respectively. The model has been designed to make investment and field development decisions from the perspective of a field operator, and to incorporate real-life exploration and development constraints faced by the operator.

The basic process-flow diagram of the endogenous component has already been shown in Figure 4D-5. The following sections are devoted to a more detailed discussion of the modeling approach.

**Inferred Reserves**

The first task of the endogenous component of DWOSS is to calculate the inferred reserves for a given year in the study. Based on the regional wellhead prices supplied by PMM and NGTDM, the crude oil and natural gas supply information generated in the exogenous component is skimmed to determine the total crude oil and natural gas reserves that are economic at those prices. It is basically the amount of crude oil and natural gas reserves that are economic to explore, develop and produce from the remaining undiscovered prospects in the deepwater Gulf of Mexico.

$$\text{INFERRED RESERVES}_{iyr,\,fuel} = \text{INFERRED RESERVES}_{iyr-1,\,fuel} + \text{FIELD RESERVES}_{fuel,\,nfield}$$

where,

| | | |
|---|---|---|
| iyr | = | Year under consideration |
| fuel | = | Fuel type, crude oil or natural gas |
| nfield | = | Fields remaining to be discovered |

Inferred reserves that do not get developed in the year they become economic get carried over to the next year and are added to the inferred reserves that come onstream at the crude oil and natural gas wellhead supply prices in the next year.

The routine also determines an average supply price for crude oil and natural gas for the total inferred reserves based on a weighted average of the individual prospect supply price. The weighting basis is the amount of technically recoverable reserves in those prospects. The total number of exploration, development and dry development wells, and the total number of production structures needed to develop the different prospects that sum up to the inferred reserves are also accounted for and carried along with the inferred reserves.

**Proved Reserves**

Due to physical and monetary constraints, only a portion of the inferred reserves are assumed to be developed in any given year. These are based on capital investment constraints, infrastructure and rig availability constraints. DWOSS has been designed to develop the inferred reserves and generate proved reserves in a given year based on the number of development wells that can be drilled in that particular year. Historic drilling activity levels in the deepwater offshore Gulf of Mexico were used to characterize the current drilling level constraints. Since the deepwater offshore Gulf of Mexico is a frontier area, the choice of growth rate in drilling activity has been left open as a user input parameter. This gives the flexibility of looking at drilling constraint as a variable and study its sensitivity over the forecast period in generating proved reserves data. The ratio of development drilling wells available to be drilled based on the drilling constraints to the total number of development wells needed to develop the total inferred reserves in a given year is multiplied by the total reserves for both crude oil and natural gas to project the proved reserves.

However, the model still has to decide between how much of the crude oil and how much of the natural gas reserves will be developed. Historically, the development of a particular fuel type has been driven by the "relative price-economics" of the development prospect for each of the two fuel types, crude oil and natural gas. Relative price economics is defined as the ratio of the price spread (difference between the average minimum acceptable supply price of the resource remaining to be discovered and the wellhead fuel price) and the fuel price (oil or gas wellhead prices). The higher the spread, the more economic it is to develop that category of resource that remains to be discovered. The proportion of development wells to be drilled for crude oil and natural gas prospects is determined by these ratios.

DWOSS is also designed to carry the reserves data for associated/dissolved gas in case of oil-bearing fields, and condensate yield in case of gas-bearing fields. The various equations describing this process are represented in Appendix B.

**Production**

Proved reserves are converted to production based on reserves-to-production (R/P) ratios. Based on the extrapolation of the reserves-to-production data for deepwater Gulf of Mexico during the last five years, a default value of 16 for the R/P ratio in DWOSS was generated, and used to convert the proved reserves data for both crude oil and natural gas into crude oil and natural gas production. The associated/dissolved gas and condensate yield reserves data are used to generate the production from these two sources for their corresponding crude oil and natural gas production counterparts.

$$\text{PRODUCTION}_{\text{fuel, iyr}} = \text{PROVED RESERVES}_{\text{fuel, iyr}} / \text{RESERVES-TO-PRODUCTION RATIO}$$

where,

| | | |
|---|---|---|
| fuel | = | Fuel type (crude oil or natural gas) |
| iyr | = | Year under consideration |

**Reserves Growth**

Reserves growth includes those resources that are expected to be added to proved reserves in a field as a consequence of extension of proved fields, through revisions of reserve estimates, and/or by addition of new payzones in these fields. Also included in this category are resources expected to be added to reserves through application of improved recovery technologies. DWOSS has been designed to allow the remaining proved reserves at the end of the year to be adjusted by a certain multiplier to estimate additional reserves growth attributable to these activities.

$$\text{RESERVES GROWTH}_{fuel,\, iyr} = (\text{PROVED RESERVES}_{fuel,\, iyr} - \text{PRODUCTION}_{fuel,\, iyr}) * \text{GROWTH RATE MULTIPLIER}$$

where,

| | | |
|---|---|---|
| fuel | = | Fuel type (crude oil or natural gas) |
| iyr | = | Year under consideration |

The reserves growth multiplier has currently been set to a value of 1.0 in the model, which means no reserves growth additions. However, the multiplier is an input parameter for that can be specified by the user.

**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 and hence on the profitability of the undiscovered crude oil and natural gas prospects. DWOSS has been designed to give due consideration to the effect of future advances in technology that may occur in the future. Since the exogenous component of the DWOSS that generates price-supply information evaluates the various deepwater offshore Gulf of Mexico prospects on the basis of existing technology choices, some way of translating the impact of future advances in technology needs to be incorporated into the analytical approach.

The endogenous component of DWOSS has been designed to modify the exploration, drilling, structure installation, and operational costs associated with undiscovered prospects that have not been added to the inferred reserves category. At the end of each year, exploration, drilling, structure installation, and operations costs for all the crude oil and natural gas prospects that remain uneconomic investments can individually reduced using unique factors for each of the cost components. The factors are currently set to 1.0 in the model, indicating no impact of advanced technology. However, the factors are input parameters and can be specified by the user.

$$\text{MASP}_{nfield,\, iyr,\, fuel,\, component} = \text{DRILLING MASP}_{nfield,\, iyr,\, fuel,\, component} * \text{ADV TECH FACTOR}$$

where,

| | | |
|---|---|---|
| nfield | = | A crude oil or natural gas field |
| iyr | = | Year under consideration |
| fuel | = | Crude oil or natural gas |
| component | = | Key cost components: Exploration, Drilling, Structure, Operations |

The minimum acceptable supply price (MASP) for each of the undiscovered remaining uneconomic prospect is also adjusted accordingly.

# 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 Deep Water Offshore Supply Submodule is presented in a separate table.

All regions specified under classification are OGSM regions unless otherwise noted.

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| Appendix B Equation | Subroutine | Variable Name | | Description | Unit | Classification |
| | | Code | Text | | | |
| 1 | OGFOR_L48 | DRILLL48 | DRILLCOST | Successful well drilling costs | 1987$ per well | Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 2 | OGFOR_L48 | DRYL48 | DRYCOST | Dry well drilling costs | 1987$ per well | Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 3 | OGFOR_OFF | DRILLOFF | DRILLCOST | Successful well drilling costs | 1987$ per well | Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 4 | OGFOR_OFF | DRYOFF | DRYCOST | Dry well drilling costs | 1987$ per well | Class(Exploratory,Developmental);8 Lower 48 offshore regions,Fuel(oil,gas |
| 5 | OGFOR_L48<br>OGFOR_OFF | LEASL48<br>LEASOFF | LEQC | Lease equipment costs | 1987$ per well | Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 6 | OGFOR_L48<br>OGFOR_OFF | OPERL48<br>OPEROFF | OPC | Operating costs | 1987$ per well | Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 7 | OG_DCF | DCFTOT | PROJDCF | Discounted cash flow for a representative project | 1987$ per project | Class(Exploratory,Developmental);6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas); 3 Alaska regions, Fuel (oil,gas) |
| 8 | OG_DCF | PVSUM(1) | PVREV | Present value of expected revenue | 1987$ per project | (Above) |
| 9 | OG_DCF | PVSUM(2) | PVROY | Present value of expected royalty payments | 1987$ per project | (Above) |
| 10 | OG_DCF | PVSUM(3) | PVPRODTAX | Present value of expected production taxes | 1987$ per project | (Above) |
| 11 | OG_DCF | PVSUM(4) | PVDRILLCOST | Present value of expected drilling costs | 1987$ per project | (Above) |
| 12 | OG_DCF | PVSUM(5) | PVEQUIP | Present value of expected lease equipment costs | 1987$ per project | (Above) |
| 13 | OG_DCF | PVSUM(8) | PVKAP | Present value of expected capital costs | 1987$ per project | (Above) |
| 14 | OG_DCF | PVSUM(6) | PVOPERCOST | Present value of expected operating costs | 1987$ per project | (Above) |

| Appendix B Equation | Variables | | | | | |
|---|---|---|---|---|---|---|
| | Subroutine | Variable Name: Code | Variable Name: Text | Description | Unit | Classification |
| 15 | OG_DCF | PVSUM(7) | PVABANDON | Present value of expected abandonment costs | 1987$ per project | (Above) |
| 16 | OG_DCF | PVSUM(13) | PVTAXBASE | Present value of expected tax base | 1987$ per project | (Above) |
| 17 | OG_DCF | XIDC | XIDC | Expensed Costs | 1987$ per project | (Above) |
| 18 | OG_DCF | DHC | DHC | Dry hole costs | 1987$ per project | (Above) |
| 19 | OG_DCF | DEPREC | DEPREC | Depreciable costs | 1987$ per project | (Above) |
| 20 | OG_DCF | PVSUM(15) | PVSIT | Expected value of state income taxes | 1987$ per project | (Above) |
| 21 | OG_DCF | PVSUM(16) | PVFIT | Expected value of federal income taxes | 1987$ per project | (Above) |
| 22-23 | OG_DCF | OG_DCF | DCF | Discounted cash flow for a representative well | 1987$ per well | (Above) |
| 24 | OGEXP_CALC | W1UNC | w | Share of total lower 48 onshore wells at class,region, fuel(unconventional gas) level | Fraction | Class(Exploratory,Developmental);6 Lower 48 onshore regions;Fuel(3 unconventional gas) |
| 25 | OGEXP_CALC | DCFUNC | UGDCFON | Discounted cash flow for unconventional gas | 1987$ | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions |
| 26 | OGEXP_CALC | W1 | w | Share of total Lower 48 wells at class,region,fuel level | Fraction | Class(Exploratory,Developmental);6 Lower 48 onshore regions;Fuel(oil,5 gas) |
| 27 | OGEXP_CALC | WDCFIR | RDCFON | Lower 48 onshore discounted cash flow | 1987$ | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions |
| 28 | OGEXP_CALC | WDCFOFFIR | RDCFOFF | Lower 48 offshore discounted cash flow | 1987$ | Class(Exploratory,Developmental) ;8 Lower 48 offshore regions |
| 29 | OGEXP_CALC | W2 | w | Share of total Lower 48 wells at class,region,fuel level | Fraction | Class(Exploratory,Developmental);6 Lower 48 onshore regions |
| 30 | OGEXP_CALC | WDCFL48 | NDCFON | Lower 48 onshore discounted cash flow | 1987$ | Class(Exploratory,Developmental) |
| 31 | OGEXP_CALC | WDCFOFF | NDCFOFF | Lower 48 offshore discounted cash flow | 1987$ | Class(Exploratory,Developmental) |

| Appendix B Equation | Variables | | | | | |
|---|---|---|---|---|---|---|
| | Subroutine | Variable Name | | Description | Unit | Classification |
| | | Code | Text | | | |
| 32-53 | OGEXP_CALC | SPENDIRK_L48 | SPENDON | Lower 48 onshore expenditures | Million 1987$ | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 54-64 | OGEXP_CALC | SPENDIRK_OFF | SPENDOFF | Lower 48 offshore expenditures | Million 1987$ | Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas) |
| 65 | OGEXP_CALC | WELLSL48 | WELLSON | Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 66 | OGEXP_CALC | SUCWELLL48 | SUCWELSON | Successful Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 67 | OGEXP_CALC | DRYWELLL48 | DRYWELON | Dry Lower 48 onshore wells drilled | Wells | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas) |
| 68 | OGALL_OFF | WELLSOFF | WELLSOFF | Lower 48 offshore wells drilled | Wells | Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas) |
| 69 | OGALL_OFF | SUCWELLOFF | SUCWELSOFF | Successful Lower 48 offshore wells drilled | Wells | Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas) |
| 70 | OGALL_OFF | DRYWELLOFF | DRYWELOFF | Dry Lower 48 offshore wells drilled | Wells | Class(Exploratory,Developmental) ;8 Lower 48 offshore regions,Fuel(oil,gas) |
| 71 | OGOUT_L48<br>OGOUT_OFF | FR1L48<br>FR1OFF | FR1 | Finding rates for new field wildcat drilling | Oil-MMB per well<br>Gas-BCF per well | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 72 | OGOUT_L48<br>OGOUT_OFF | DELTA1L48<br>DELTA1OFF | δ1 | Finding rate decline parameters for new field wildcat drilling | Fraction | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 73 | OGOUT_L48<br>OGOUT_OFF | CUMR1L48<br>CUMR1OFF | CUMRES1 | Cumulative proved reserves added by new field discoveries | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 74 | OGOUT_L48<br>OGOUT_OFF | NDRL48<br>NDROFF | NRD | Proved reserves added by new field discoveries | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 75 | OGOUT_L48<br>OGOUT_OFF | NDIRL48<br>NDIROFF | I | Inferred reserves added by new field discoveries | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |

| Appendix B Equation | Variables | | | | | |
|---|---|---|---|---|---|---|
| | Subroutine | Variable Name: Code | Variable Name: Text | Description | Unit | Classification |
| 76 | OGOUT_L48<br>OGOUT_OFF | FR2L48<br>FR2OFF | FR2 | Finding rates for developmental wells | Oil-MMB per well<br>Gas-BCF per well | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 77 | OGOUT_L48<br>OGOUT_OFF | DELTA2L48<br>DELTA2OFF | δ2 | Finding rate decline parameters for developmental wells | Fraction | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 78 | OGOUT_L48<br>OGOUT_OFF | CUMR2L48<br>CUMR2OFF | CUMRES2 | Cumulative reserve revisions | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 79 | OGOUT_L48<br>OGOUT_OFF | REVL48<br>REVOFF | REV | Reserve revisions | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 80 | OGOUT_L48<br>OGOUT_OFF | FR3L48<br>FR3OFF | FR3 | Finding rates for other exploratory drilling | Oil-MMB per well<br>Gas-BCF per well | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 81 | OGOUT_L48<br>OGOUT_OFF | DELTA3L48<br>DELTA3OFF | δ3 | Finding rate decline parameters for other exploratory wells | Fraction | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 82 | OGOUT_L48<br>OGOUT_OFF | CUMR3L48<br>CUMR3OFF | CUMRES3 | Cumulative reserve extensions | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 83 | OGOUT_L48<br>OGOUT_OFF | EXTL48<br>EXTOFF | EXT | Reserve extensions | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 84 | OGOUT_L48<br>OGOUT_OFF | RESADL48<br>RESADOFF | RA | Total additions to proved reserves | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |
| 85 | OGOUT_L48<br>OGOUT_OFF<br>OGFOR_AK | RESBOYL48<br>RESBOYOFF<br>BOYRESCOAK<br>BOYRESNGAK | R | End of year reserves for current year | Oil-MMB<br>Gas-BCF | 6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas);3 Alaska regions,Fuel(oil,gas) |
| 86 | OGOUT_L48<br>OGOUT_OFF | PRRATL48<br>PRRATOFF | PR | Production to reserves ratios | Fraction | Class(Exploratory,Developmental) ;6 Lower 48 onshore regions,Fuel(oil,5 gas);8 Lower 48 offshore regions,Fuel(oil,gas) |

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| Appendix B Equation | Subroutine | Variable Name | | Description | Unit | Classification |
| | | Code | Text | | | |
| 87 | OGCOMP_AD | OGPRDAD | ADGAS | Associated-dissolved gas production | BCF | 6 Lower 48 onshore regions, 3 Lower 48 offshore regions |
| 88 | OGCOST_AK | DRILLAK | DRILLCOST | Drilling costs | 1987$ per well | Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas) |
| 89 | OGCOST_AK | LEASAK | EQUIP | Lease equipment costs | 1987$ per well | Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas) |
| 90 | OGCOST_AK | OPERAK | OPCOST | Operating costs | 1987$ per well | Class(Exploratory,Developmental);3 Alaska regions,Fuel (oil, gas) |
| 91 | OGFOR_AK | TOTGRR | TRR | Alaska total gross revenue requirements | Million 1987$ | NA |
| 92 | OGFOR_AK | TOTDEP | TOTDEP | Alaska total depreciation | Million 1987$ | NA |
| 93 | OGFOR_AK | MARTOT | MARGIN | Alaska total after tax margin | Million 1987$ | NA |
| 94 | OGFOR_AK | RECTOT | DEFRETREC | Alaska total recovery of differed returns | Million 1987$ | NA |
| 95 | OGFOR_AK | TXALLW | TXALLW | Alaska income tax allowance | Million 1987$ | NA |
| 96 | OGCAN_DCF | CF | NCF | Net cash flow | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 97 | OGCAN_DCF | OGCAN_DCF | PROJDCF | Discounted cash flow | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 98 | OGCAN_DCF | REV | REV | Revenues | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 99 | OGCAN_DCF | ROY | ROY | Royalty payments | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 100 | OGCAN_DCF | DRILL | DRILLCOST | Successful well drilling costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 101 | OGCAN_DCF | DRILL | DRYCOST | Dry hole drilling costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 102 | OGCAN_DCF | EQUIP | EQUIP | Lease equipment costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 103 | OGCAN_DCF | OPER | OPERCOST | Operating costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |

| | Variables | | | | | |
|---|---|---|---|---|---|---|
| Appendix B Equation | Subroutine | Variable Name | | Description | Unit | Classification |
| | | Code | Text | | | |
| 104 | OGCAN_DCF | FTI | FTI | Federal tax base | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 105 | OGCAN_DCF | XIDC | XIDC | Expensed costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 106 | OGCAN_DCF | AIDC | DEPREC | Depreciable costs | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 107 | OGCAN_DCF | RA | RA | Resource allowance | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 108 | OGCAN_DCF | DA | DA | Depletion allowance | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 109 | OGCAN_DCF | PTI | PTI | Provincial tax base | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 110 | OGCAN_DCF | PROVTAX | PROVTAX | Provincial income taxes | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 111 | OGCAN_DCF | FEDTAX | FEDTAX | Federal income taxes | 1987$ per project | Class(exploratory,developmental); Fuel(oil,gas) |
| 112 | OGOUT_IMP | WELLSCAN | WELLS | Canadian wells drilled | Wells | Fuel(oil,gas) |
| 113 | OGOUT_IMP | FRCAN | FR | Canadian finding rate | Oil:MMB per well Gas:BCF per well | Fuel(oil,gas) |
| 114 | OGOUT_IMP | DELTACAN | δ | Canadian finding rate decline parameter | Fraction | Fuel(oil,gas) |
| 115 | OGOUT_IMP | RESADCAN | RA | Canadian reserve additions | Oil:MMB Gas:BCF | Fuel(oil,gas) |
| 116 | OGOUT_IMP | CUMRCAN | CUMRES | Cumulative Canadian reserve additions | Oil:MMB Gas:BCF | Fuel(oil,gas) |
| 117 | OGOUT_IMP | RESBOYCAN | R | Canadian reserves | Oil:MMB Gas:BCF | Fuel(oil,gas) |
| 118 | OGOUT_IMP | PRRATCAN | PR | Canadian production to reserves ratio | Fraction | Fuel(oil,gas) |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGFOR_L48<br>OGINIT_L48 | ADVLTXL48 | PRODTAX | Lower 48 onshore ad valorem tax rates | Fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7 |
| OGFOR_OFF<br>OGINIT_OFF | ADVLTXOFF | PRODTAX | Offshore ad valorem tax rates | Fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Colorado School of Mines. Oil Propert Evaluation, 1983, p. 9-7 |
| OGINIT_AK<br>OGPIP_AK | ANGTSMAX | -- | ANGTS maximum flow | BCF/D | Alaska | National Petroleum Council |
| OGINIT_AK<br>OGPIP_AK | ANGTSPRC | -- | Minimum economic price for ANGTS start up | 1987$/MCF | Alaska | National Petroleum Council |
| OGINIT_AK<br>OGPIP_AK | ANGTSRES | -- | ANGTS reserves | BCF | Alaska | National Petroleum Council |
| OGINIT_AK<br>OGPIP_AK | ANGTSYR | -- | Earliest start year for ANGTS flow | Year | NA | National Petroleum Council |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORCOGC | -- | EOR cogeneration electric capacity (reference case) | MW | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORCOGG | -- | EOR cogeneration electric generation (reference case) | MWh | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORCON | -- | EOR crude oil consumption (reference case) | MB | 6 Lower 48 onshore regions | Not Used |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORNGC | -- | EOR natural gas consumption (reference case) | MCF | 6 Lower 48 onshore regions; 2 EOR technologies (primary,other) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORNGP | -- | EOR natural gas production (reference case) | MCF | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | BGQEORPR | -- | EOR crude oil production (reference case) | MB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGEXPAND_LNG<br>OGINIT_LNG | BUILDLAG | -- | Buildup period for expansion of LNG facilities | Year | NA | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Subroutine | Variable Name | | Description | Unit | Classification | Source |
| | Code | Text | | | | |
| OGFOR_IMP<br>OGINIT_IMP | CPRDCAN | COPRD | Canadian coproduct rate | Fraction | Canada; Fuel (oil, gas) | Derived using data from the Canadian Petroleum Association |
| OGFOR_L48<br>OGINIT_L48 | CPRDL48 | COPRD | Lower 48 onshore coproduct rate | Fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF | CPRDOFF | COPRD | Offshore coproduct rate | Fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP<br>OGINIT_RES<br>OGOUT_IMP | CURPRRCAN | omega | Canadian 1989 P/R ratio | Fraction | Canada; Fuel (oil, gas) | Derived using data from the Canadian Petroleum Association |
| OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | CURPRRL48 | omega | Lower 48 initial P/R ratios | Fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | CURPRROFF | omega | Offshore initial P/R ratios | Fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | CURPRRTDM | -- | Lower 48 initial P/R ratios at NGTDM level | Fraction | 17 OGSM/NGTDM regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP<br>OGINIT_RES<br>OGOUT_IMP | CURRESCAN | R | Canadian 1989 end of year reserves | MMB<br>BCF | Canada; Fuel (oil, gas) | Canadian Petroleum Association |
| OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | CURRESL48 | R | Lower 48 onshore initial reserves | MMB<br>BCF | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Derived from Annual Reserves Report Data |
| OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | CURRESOFF | R | Offshore initial reserves | MMB<br>BCF | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Derived from Annual Reserves Report Data |
| OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | CURRESTDM | -- | Lower 48 natural gas reserves at NGTDM level | MMB<br>BCF | 17 OGSM/NGTDM regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGOUT_L48 | DECFAC | DECFAC | Inferred resource simultaneous draw down decline rate adjustment factor | Fraction | NA | Office of Integrated Analysis and Forecasting |

## Data

| Subroutine | Variable Name | | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| | Code | Text | | | | |
| OGFOR_IMP<br>OGINIT_IMP | DECLCAN | -- | Canadian decline rates | Fraction | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48<br>WELL | DECLL48 | -- | Lower 48 onshore decline rates | Fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF<br>WELL | DECLOFF | -- | Offshore decline rates | Fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_AK<br>OGPRO_AK | DECLPRO | -- | Alaska decline rates for currently producing fields | Fraction | Field | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | DEPLETERT | DEPLRT | Depletion rate | Fraction | NA | Office of Integrated Analysis and Forecasting |
| OGDEV_AK<br>OGINIT_AK<br>OGSUP_AK | DEV_AK | -- | Alaska drilling schedule for developmental wells | Wells per year | 3 Alaska regions; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGDCF_AK<br>OGFOR_L48<br>OGFOR_OFF<br>OGINIT_BFW | DISC | disc | Discount rate | Fraction | National | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | DISRT | disc | Discount rate | Fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGCOST_AK<br>OGINIT_AK | DRILLAK | DRILL | Alaska drilling cost (not including new field wildcats) | 1990$/well | Class (exploratory, developmental);<br>3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | DRILLCAN | DRILL | Canadian initial drilling costs | 1987$ | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGALL_OFF<br>OGFOR_OFF<br>OGINIT_OFF | DRILLOFF | DRILL | Offshore drilling cost | 1987$ | 8 Lower 48 offshore subregions | Mineral Management Service |
| OGCOST_AK<br>OGINIT_AK | DRLNFWAK | -- | Alaska drilling cost of a new field wildcat | 1990$/well | 3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |

## Data

| Subroutine | Variable Name | | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| | Code | Text | | | | |
| OGDCF_AK<br>OGDEV_AK<br>OGINIT_AK<br>OGNEW_AK | DRYAK | DRY | Alaska dry hole cost | 1990$/hole | Class (exploratory, developmental);<br>3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | DRYCAN | DRY | Canadian dry hole cost | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| OGALL_OFF<br>OGEXP_CALC<br>OGFOR_OFF<br>OGINIT_OFF | DRYOFF | DRY | Offshore dry hole cost | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions | Minerals Management Service |
| OGFOR_OFF<br>OGINIT_OFF | DVWELLOFF | -- | Offshore development project drilling schedules | wells per year | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Minerals Management Service |
| OGFOR_L48<br>OGINIT_L48 | DVWLCBML48 | -- | Lower 48 development project drilling schedules for coalbed methane | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | DVWLDGSL48 | -- | Lower 48 development project drilling schedules for deep gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | DVWLDVSL48 | -- | Lower 48 development project drilling schedules for devonian shale | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | DVWLGASCAN | -- | Canadian development gas drilling schedule | wells per project per year | Canada | Not Used |
| OGFOR_IMP<br>OGINIT_IMP | DVWLOILCAN | -- | Canadian development oil drilling schedule | wells per project per year | Canada | Not Used |
| OGFOR_L48<br>OGINIT_L48 | DVWLOILL48 | -- | Lower 48 development project drilling schedules for oil | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | DVWLSGSL48 | -- | Lower 48 development project drilling schedules for shallow gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | DVWLTSGL48 | -- | Development project drilling schedules for tight gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | ELASTL48 | -- | Lower 48 onshore production elasticity values | Fraction | 6 OGSm Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGINIT_RES<br>OGOUT_OFF | ELASTOFF | -- | Offshore production elasticity values | Fraction | 8 Lower 48 offshore subregions | Office of Integrated Analysis and Forecasting |
| OGCOMP_EMIS<br>OGINIT_EMIS | EMCO | -- | Emission factors for crude oil production | Fraction | Census regions | EPA - Energy Technology Characterizations Handbook |
| OGCOMP_EMIS<br>OGINIT_EMIS | EMFACT | -- | Emission factors | MMB<br>MMCF | Census regions | EPA - Energy Technology Characterizations Handbook |
| OGCOMP_EMIS<br>OGINIT_EMIS | EMNG | -- | Emission factors for natural gas production | Fraction | Census regions | EPA - Energy Technology Characterizations Handbook |
| OGCOST_AK<br>OGINIT_AK | EQUIPAK | EQUIP | Alaska lease equipment cost | 1990$/well | Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas) | U.S. Geological Survey |
| OGEXP_CALC<br>OGINIT_BFW | EXOFFRGNLAG | -- | Offshore exploration & development regional expenditure (1989) | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions | Office of Integrated Analysis and Forecasting |
| OGDEV_AK<br>OGINIT_AK<br>OGSUP_AK | EXP_AK | -- | Alaska drilling schedule for other exploratory wells | wells per year | 3 Alaska regions | Office of Integrated Analysis and Forecasting |
| OGCAN_DCF<br>OGFOR_IMP<br>OGINIT_IMP | EXPENSE | EXP | Fraction of drill costs that are expensed | fraction | Class (exploratory, developmental) | Canadian Tax Code |
| OGFOR_OFF<br>OGINIT_OFF | EXWELLOFF | -- | Offshore exploratory project drilling schedules | wells per year | 8 Lower 48 offshore subregions | Minerals Management Service |
| OGFOR_L48<br>OGINIT_L48 | EXWLCBML48 | -- | Lower 48 exploratory project drilling schedules for coalbed methane | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | EXWLDGSL48 | -- | Lower 48 exploratory and developmental project drilling schedules for deep gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | EXWLDVSL48 | -- | Lower 48 exploratory project drilling schedules for devonian shale | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGFOR_IMP<br>OGINIT_IMP | EXWLGASCAN | -- | Canadian exploratory gas drilling schedule | wells per year | Canada | Not Used |
| OGFOR_IMP<br>OGINIT_IMP | EXWLOILCAN | -- | Canadian exploratory oil drilling schedule | wells per year | Canada | Not Used |
| OGFOR_L48<br>OGINIT_L48 | EXWLOILL48 | -- | Lower 48 exploratory project drilling schedules for oil | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | EXWLSGSL48 | -- | Lower 48 exploratory project drilling schedules for shallow gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | EXWLTSGL48 | -- | Lower 48 exploratory project drilling schedules for tight gas | wells per year | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGDEV_AK<br>OGFAC_AK<br>OGINIT_AK<br>OGSUP_AK | FACILAK | -- | Alaska facility cost (oil field) | 1990$/bls | Field size class | U.S. Geological Survey |
| OGFOR_IMP<br>OGINIT_IMP | FEDTXCAN | FDRT | Canadian corporate tax rate | fraction | Canada | Petroleum Fiscal Systems in Canada - Energy, Mines & Resources |
| OGDCF_AK<br>OGEXP_CALC<br>OGFOR_L48<br>OGFOR_OFF<br>OGINIT_BFW | FEDTXR | FDRT | U.S. federal tax rate | fraction | Canada | U.S. Tax Code |
| OGFOR_IMP<br>OGINIT_IMP | FLOWCAN | -- | Canadian flow rates | bls, MCF per year | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | FLOWL48 | -- | Lower 48 onshore flow rates | bls, MCF per year | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | EIA, Office of Oil and Gas |
| OGFOR_OFF<br>OGINIT_OFF | FLOWOFF | -- | Offshore flow rates | bls, MCF per year | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_LNG<br>OGPROF_LNG | FPRDCST | -- | Foreign production costs | 1991$/MCF per year | LNG Source Country | National Petroleum Council |

**Data**

| Subroutine | Variable Name | | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| | Code | Text | | | | |
| OGINIT_IMP<br>OGOUT_IMP | FRCAN | FR | Canadian initial finding rate | MMB<br>BCF<br>per well | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP<br>OGOUT_IMP | FRMINCAN | FRMIN | Canadian minimum economic finding rate | MMB<br>BCF<br>per well | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | FRMINL48 | FRMIN | Lower 48 onshore minimum exploratory well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGOUT_OFF | FRMINOFF | FRMIN | Offshore minimum exploratory well finding rate | MMB<br>BCF<br>per well | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | FR1L48 | FR1 | Lower 48 onshore new field wildcat well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGOUT_OFF | FR1OFF | FR1 | Offshore new field wildcat well finding rate | MMB<br>BCF<br>per well | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | FR2L48 | FR3 | Lower 48 onshore developmental well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGOUT_OFF | FR2OFF | FR3 | Offshore developmental well finding rate | MMB<br>BCF<br>per well | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | FR3L48 | FR2 | Lower 48 other exploratory well finding rate | MMB<br>BCF<br>per well | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF<br>OGOUT_OFF | FR3OFF | FR2 | Offshore other exploratory well finding rate | MMB<br>BCF<br>per well | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_AK<br>OGINIT_AK<br>OGNEW_AK | FSZCOAK | — | Alaska oil field size distributions | MMB | 3 Alaska regions | U.S. Geological Survey |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Subroutine | Variable Name | | Description | Unit | Classification | Source |
| | Code | Text | | | | |
| OGFOR_AK<br>OGINIT_AK<br>OGNEW_AK | FSZNGAK | -- | Alaska gas field size distributions | BCF | 3 Alaska regions | U.S. Geological Survey |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORCOGC | -- | EOR cogeneration electric capacity (high oil price case) | MW | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORCOGG | -- | EOR cogeneration electric generation (high oil price case) | MWh | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORCON | -- | EOR crude oil consumption (high oil price case) | MB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORNGC | -- | EOR natural gas consumption (high oil price case) | MCF | 6 Lower 48 onshore regions; 2 EOR technologies (primary,other) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORNGP | -- | EOR natural gas production (high oil price case) | MCF | 6 Lower 48 onshore regions | Not Used |
| OGINIT_EOR<br>OGOUT_EOR | HGQEORPR | -- | EOR crude oil production (high oil price case) | MB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGINIT_L48 | HISTADL48 | -- | Lower 48 historical associated-dissolved natural gas reserves | BCF | NA | Annual Reserves report |
| OGINIT_OFF | HISTADOFF | -- | Offshore historical associated-dissolved natural gas reserves | BCF | NA | Annual Reserves Report |
| OGINIT_AK<br>OGPRO_AK | HISTPRDCO | -- | Alaska historical crude oil production | MB/D | Field | Alaska Oil and Gas Conservation Commission |
| OGINIT_L48 | HISTPRRL48 | -- | Lower 48 historical P/R ratios | fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Derived from Annual Reserves Report |
| OGINIT_OFF | HISTPRROFF | -- | Offshore historical P/R ratios | fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Derived from Annual Reserves Report |
| OGINIT_L48 | HISTPRRTDM | -- | Lower 48 onshore historical P/R ratios at the NGTDM level | fraction | 17 OGSM/NGTDM regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |

## Data

| Subroutine | Variable Name | | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| | Code | Text | | | | |
| OGINIT_L48 | HISTRESL48 | -- | Lower 48 onshore historical beginning-of-year reserves | MMB BCF | 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Annual Reserves Report |
| OGINIT_OFF | HISTRESOFF | -- | Offshore historical beginning-of-year reserves | MMB BCF | 8 Lower 48 offshore subregions; Fuel (oil, gas) | Annual Reserves Report |
| OGINIT_L48 | HISTRESTDM | -- | Lower 48 onshore historical beginning-of-year reserves atthe NGTDM level | MMB BCF | 17 OGSM/NGTDM regions; Fuel (oil, 5 gas) | Annual Reserves Report |
| OGDCF_AK OGFOR_L48 OGFOR_OFF OGINIT_BFW | INFL | infl | U.S. inflation rate | fraction | National | Office of Integrated Analysis and Forecasting |
| OGINIT_L48 OGOUT_L48 | INFRSVL48 | I | Lower 48 onshore inferred reserves | MMB BCF | 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_OFF OGOUT_OFF | INFRSVOFF | I | Offshore inferred reserves | MMB BCF | 8 Lower 48 offshore subregions; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP OGINIT_IMP | INFRT | infl | Canadian inflation rate | fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP OGINIT_IMP | INVESTRT | INVESTCR | Canadian investment tax credit | fraction | Canada | Not Used |
| OGDCF_AK OGINIT_AK | KAPFRCAK | EXKAP | Alaska drill costs that are tangible & must be depreciated | fraction | Alaska | U.S. Tax Code |
| OGFOR_L48 OGINIT_L48 | KAPFRCL48 | EXKAP | Lower 48 onshore drill costs that are tangible & must be depreciated | fraction | Class (exploratory, developmental) | U.S. Tax Code |
| OGFOR_OFF OGINIT_OFF | KAPFRCOFF | EXKAP | Offshore drill costs that are tangible & must be depreciated | fraction | Class (exploratory, developmental) | U.S. Tax Code |
| OGFOR_L48 OGINIT_L48 | KAPSPNDL48 | KAP | Lower 48 onshore other capital expenditures | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Not used |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGFOR_OFF<br>OGINIT_OFF | KAPSPNDOFF | KAP | Offshore other capital expenditures | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions | Minerals Mangement Service |
| OGFOR_L48<br>OGINIT_L48 | LAGDRILL48 | -- | 1989 Lower 48 drill cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | LAGDRYL48 | -- | 1989 Lower 48 dry hole cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | LAGLEASL48 | -- | 1989 Lower 48 lease equipment cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | LAGOPERL48 | -- | 1989 Lower 48 operating cost | 1987$ | Class (exploratory, developmental); 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | LEASCAN | EQUIP | Canadian lease equipment cost | 1987$ | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF | LEASOFF | EQUIP | Offshore lease equipment cost | 1987$ per project | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions | Minerals Mangement Service |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORCOGC | -- | Electric cogeneration capacity from EOR | MW | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORCOGG | -- | Electric cogeneration volumes from EOR | MWh | 6 Lower 48 onshore regions; 2 usages (utility,non-utility) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORCON | -- | EOR crude oil consumption | MB | 6 Lower 48 onshore regions | Not Used |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Subroutine | Variable Name | | Description | Unit | Classification | Source |
| | Code | Text | | | | |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORNGC | -- | EOR natural gas consumption | MCF | 6 Lower 48 onshore regions; 2 EOR technologies (primary,other) | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORNGP | -- | EOR natural gas production | MCF | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGINIT_EOR<br>OGOUT_EOR | LGQEORPR | -- | EOR crude oil production | MB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGEXPAND_LNG<br>OGINIT_LNG | LIQCAP | -- | Liquefaction capacity | BCF | LNG Source Country | National Petroleum Council |
| OGINIT_LNG<br>OGPROF_LNG | LIQCST | -- | Liquefaction costs | 1991$/MCF | LNG Source Country | National Petroleun Council |
| OGEXPAND_LNG<br>OGPROF_LNG | LIQSTAGE | -- | Liquefaction stage | NA | NA | National Petroleum Council |
| OGFOR_AK<br>OGINIT_AK<br>OGPRO_AK | MAXPRO | -- | Alaska maximum crude oil production | MB/D | Field | Announced Plans |
| OGINIT_IMP<br>OGOUT_MEX | MEXEXP | -- | Exports from Mexico | BCF | 3 US/Mexican border crossing | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP<br>OGOUT_MEX | MEXIMP | -- | Imports from Mexico | BCF | 3 US/Mexican border crossing | Office of Integrated Analysis and Forecasting |
| OGINIT_AK<br>OGNEW_AK | NFW_AK | -- | Alaska drilling schedule for new field wildcats | wells | NA | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF | NFWCOSTOFF | COSTEXP | Offshore new field wildcat cost | 1987$ | Class (exploratory, developmental); 8 Lower 48 offshore subregions | Minerals Management Service |
| OGFOR_OFF<br>OGINIT_OFF | NFWELLOFF | -- | Offshore exploratory and developmental project drilling schedules | wells per project per year | Class (exploratory, developmental); r=1 | Minerals Management Service |
| OGINIT_L48<br>OGINIT_RES<br>OGOUT_L48 | NGTDMMAP | -- | Mapping of NGTDM regions to OGSM regions | NA | 17 OGSM/NGTDM regions | Office of Integrated Analysis and Forecasting |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| Subroutine | Variable Name | | Description | Unit | Classification | Source |
| | Code | Text | | | | |
| OGINIT_IMP | OGCNBLOSS | -- | Gas lost in transit to border | BCF | 6 US/Canadian border crossings | Not Used |
| OGINIT_IMP | OGCNCAPB | -- | Canadian capacities at borders - base case | BCF | 6 US/Canadian border crossing | Derived from Natural Gas Annual |
| OGINIT_IMP | OGCNCAPH | -- | Canadian capacities at borders - high WOP case | BCF | 6 US/Canadian border crossing | Derived from Natural Gas Annual |
| OGINIT_IMP | OGCNCAPL | -- | Canadian capacities at borders - low WOP case | BCF | 6 US/Canadian border crossing | Derived from Natural Gas Annual |
| OGINIT_IMP OGOUT_IMP | OGCNCON | -- | Canadian gas consumption | BCF | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP | OGCNDEM | -- | Canadian demand calculation parameters | NA | NA | Not Used |
| OGINIT_IMP | OGCNDMLOSS | -- | Gas lost from wellhead to Canadian demand | BCF | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP | OGCNEXLOSS | -- | Gas lost from US export to Canadian demand | BCF | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP | OGCNFLW | -- | 1989 flow volumes by border crossing | BCF | 6 US/Canadian border crossings | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP | OGCNPARM1 | -- | Actual gas allocation factor | fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP | OGCNPARM2 | -- | Responsiveness of flow to different border prices | fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGINIT_PRICE | OGCNPPRD | -- | Canadian price of oil and gas | oil: 87$s/B gas: 87$s/mcf | Canada | NGTDM |
| OGPIP_AK OGPROF_LNG | OGPNGIMP | -- | Natural gas import price | 87$s/mcf | US/Canadian & US/Mexican border crossings and LNG destination points | NGTDM |
| OGFOR_IMP OGINIT_IMP | OPERCAN | OPCOST | Canadian operating cost | $ 1987 | Canada; Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |

## Data

| Subroutine | Variable Name Code | Variable Name Text | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| OGFOR_OFF<br>OGINIT_OFF | OPEROFF | OPCOST | Offshore operating cost | 1987$ per well per year | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions | Mineral Management Service |
| OGDCF_AK<br>OGINIT_AK | PRJAK | n | Alaska oil project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | PRJL48 | n | Lower 48 project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF | PRJOFF | n | Offshore project life | Years | Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | PROVTXCAN | PROVRT | Canadian provincial corporate tax rates | fraction | Canada | Petroleum Fiscal Systems in Canada - Energy, Mines & Resources |
| OGFOR_AK<br>OGINIT_AK<br>OGPRO_AK | PROYR | -- | Start year for known fields in Alaska | Year | Field | Announced Plans |
| OGEXPAND_LNG<br>OGINIT_LNG<br>OGLNG_OUT | QLNG | -- | LNG operating flow capacity | BCF | LNG destination points | National Petroleum Council |
| OGEXPAND_LNG<br>OGINIT_LNG<br>OGLNG_OUT | QLNGMAX | -- | LNG maximum capacity | BCF | LNG destination Points | National Petroleum Council |
| OGDCF_AK<br>OGINIT_AK | RCPRDAK | m | Alaska recovery period of intangible & tangible drill cost | Years | Alaska | U.S. Tax Code |
| OGFOR_IMP<br>OGINIT_IMP | RCPRDCAN | m | Canada recovery period of intangible & tangible drill cost | Years | Canada | Petroleum Fiscal Systems in Canada - Energy, Mines & Resources |
| OGFOR_L48<br>OGINIT_L48 | RCPRDL48 | m | Lower 48 recovery period for intangible & tangible drill cost | Years | Lower 48 Onshore | U.S. Tax Code |
| OGFOR_OFF<br>OGINIT_OFF | RCPRDOFF | m | Offshore recovery period intangible & tangible drill cost | Years | Lower 48 Offshore | U.S. Tax Code |
| OGFOR_AK<br>OGINIT_AK<br>OGPRO_AK | RECRES | -- | Alaska crude oil resources for known fields | MMB | Field | OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity* |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGINIT_LNG<br>OGPROF_LNG | REGASCST | -- | Regasification costs | 1991$/MCF per year | Operational Stage; LNG destination points | National Petroleum Council |
| OGEXPAND_LNG<br>OGINIT_LNG | REGASEXPAN | -- | Regasification capacity | BCF | LNG destination points | National Petroleum Council |
| OGEXPAND_LNG<br>OGINIT_LNG<br>OGPROF_LNG | REGASSTAGE | -- | Regasification stage | NA | NA | National Petroleum Council |
| OGINIT_IMP<br>OGOUT_IMP | RESBASE | Q | Canadian recoverable resource estimate | MMB<br>BCF | Canada | Canadian Geological Survey |
| OGFOR_IMP<br>OGINIT_IMP | ROYRATE | ROYRT | Canadian royalty rate | fraction | Canada | Petroleum Fiscal Systems in Canada - Energy, Mines & Resources |
| OGDCF_AK<br>OGFOR_L48<br>OGINIT_BFW | ROYRT | ROYRT | Alaska royalty rate | fraction | Alaska | U.S. Geological Survey |
| OGINIT_AK<br>OGSEVR_AK | SEVTXAK | PRODTAX | Alaska severance tax rates | fraction | Alaska | U.S. Geological Survey |
| OGFOR_L48<br>OGINIT_L48 | SEVTXL48 | PRODTAX | Lower 48 onshore severance tax rates | fraction | 6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Commerce Clearing House |
| OGFOR_OFF<br>OGINIT_OFF | SEVTXOFF | PRODTAX | Offshore severance tax rates | fraction | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Commerce Clearing House |
| OGEXP_CALC<br>OGINIT_BFW | SPENDIRKLAG | -- | 1989 Lower 48 exploration & development expenditures | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | SPENDLAGL48 | -- | 1989 Lower 48 onshore exploration & development expenditures | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |

## Data

| Subroutine | Variable Name Code | Variable Name Text | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| OGEXP_CALC<br>OGINIT_BFW | SPENDLAGOFF | -- | 1989 offshore exploration & development expenditures | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | SPENDRGNLAG | -- | 1989 Lower 48 exploration & development regional expenditures | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | SPEXLAGL48 | -- | 1988 Lower 48 onshore exploration expenditures | 1987$ | Lower 48 | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | SPEXLAGOFF2 | -- | 1988 offshore exploration expenditures | 1987$ | Lower 48 | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | SPEXOFFIRKLAG | -- | 1989 offshore exploration & development expenditures | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGDCF_AK<br>OGDEV_AK<br>OGINIT_AK<br>OGNEW_AK | SRAK | SR | Alaska drilling success rates | fraction | Alaska | Office of Oil and Gas |
| OGFOR_IMP<br>OGINIT_IMP<br>OGFOR_IMP | SRCAN | SR | Canada drilling success rates | fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGEXP_FIX<br>OGFOR_L48<br>OGINIT_L48<br>OGOUT_L48 | SRL48 | SR | Lower 48 drilling success rates | fraction | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGALL_OFF<br>OGFOR_OFF<br>OGINIT_OFF<br>OGOUT_OFF | SROFF | SR | Offshore drilling success rates | fraction | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Minerals Management Service |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGEXPAND_LNG<br>OGINIT_LNG | STARTLAG | -- | Number of year between stages (regasification and liquefaction) | years | NA | Office of Integrated Analysis and Forecasting |
| OGDCF_AK<br>OGINIT_AK | STTXAK | STRT | Alaska state tax rate | fraction | Alaska | U.S. Geological Survey |
| OGEXP_CALC<br>OGFOR_L48<br>OGINIT_L48 | STTXL48 | STRT | State tax rates | fraction | 6 Lower 48 onshore regions | Commerce Clearing House |
| OGEXP_CALC<br>OGFOR_OFF<br>OGINIT_L48 | STTXOFF | STRT | State tax rates | fraction | 8 Lower 48 offshore subregions | Commerce Clearing House |
| OGCOST_AK<br>OGINIT_AK | TECHAK | TECH | Alaska technology factors | fraction | Alaska | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | TECHCAN | TECH | Canada technology factors applied to costs | fraction | Canada | Office of Integrated Analysis and Forecasting |
| OGFOR_IMP<br>OGINIT_IMP | TECHL48 | TECH | Lower 48 onshore technology factors applied to costs | fraction | Lower 48 Onshore | Office of Integrated Analysis and Forecasting |
| OGFOR_OFF<br>OGINIT_OFF | TECHOFF | TECH | Offshore technology factors applied to costs | fraction | Lower 48 Offshore | Office of Integrated Analysis and Forecasting |
| OGINIT_LNG<br>OGPROF_LNG | TRANCST | -- | LNG transporation costs | 1990/MCF | NA | National Petroleum Council |
| OGDCF_AK<br>OGINIT_AK | TRANSAK | TRANS | Alaska transportation cost | 1990$ | 3 Alaska regions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGFOR_L48<br>OGINIT_L48 | TRANSL48 | TRANS | Lower 48 onshore expected transportation costs | NA | 6 Lower 48 onshore regions; Fuel (oil, 5 gas) | Not Used |
| OGFOR_OFF<br>OGINIT_OFF | TRANSOFF | TRANS | Offshore expected transportation costs | NA | 8 Lower 48 offshore subregions; Fuel (oil, gas) | Not Used |
| OGINIT_OFF<br>OGOUT_OFF | UNRESOFF | Q | Offshore undiscovered resources | MMB<br>BCF | 8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGINIT_L48<br>OGOUT_L48 | URRCRDL48 | Q | Lower 48 onshore undiscovered recoverable crude oil resources | MMB | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |

**Data**

| Subroutine | Variable Name | | Description | Unit | Classification | Source |
|---|---|---|---|---|---|---|
| | Code | Text | | | | |
| OGINIT_L48<br>OGOUT_L48 | URRTDM | -- | Lower 48 onshore undiscovered recoverable natural gas resources | TCF | 6 Lower 48 onshore regions | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFIRKLAG | -- | 1989 Lower 48 exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFIRLAG | -- | 1989 Lower 48 regional exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>6 Lower 48 onshore regions; | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFL48LAG | -- | 1989 Lower 48 onshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFOFFIRKLAG | -- | 1989 offshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFOFFIRLAG | -- | 1989 offshore regional exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions; | Office of Integrated Analysis and Forecasting |
| OGEXP_CALC<br>OGINIT_BFW | WDCFOFFLAG | -- | 1989 offshore exploration & development weighted DCFs | 1987$ | Class (exploratory, developmental) | Office of Integrated Analysis and Forecasting |
| OGINIT_IMP<br>OGOUT_IMP | WELLAGCAN | WELLS | 1989 wells drilled in Canada | Wells per year | Fuel (oil, gas) | Canadian Petroleum Association |
| OGEXP_CALC<br>OGEXP_FIX<br>OGINIT_L48 | WELLAGL48 | WELLSON | 1989 Lower 48 wells drilled | Wells per year | Class (exploratory, developmental);<br>6 Lower 48 onshore regions;<br>Fuel (oil, 5 gas) | Office of Oil & Gas |

| Data | | | | | | |
|---|---|---|---|---|---|---|
| **Subroutine** | **Variable Name** | | **Description** | **Unit** | **Classification** | **Source** |
| | **Code** | **Text** | | | | |
| OGALL_OFF<br>OGEXP_CALC<br>OGINIT_OFF | WELLAGOFF | WELLSOFF | 1989 offshore wells drilled | Wells per year | Class (exploratory, developmental);<br>8 Lower 48 offshore subregions;<br>Fuel (oil, gas) | Office of Oil & Gas |
| OGCANDCF<br>OGFOR_IMP<br>OGINIT_IMP | WELLLIFE | n | Canadian project life | Years | Canada | Office of Integrated Analysis and Forecasting |
| OGDCF_AK<br>OGINIT_AK | XDCKAPAK | XDCKAP | Alaska intangible drill costs that must be depreciated | fraction | Alaska | U.S. Tax Code |
| OGFOR_L48<br>OGINIT_L48 | XDCKAPL48 | XDCKAP | Lower 48 intangible drill costs that must be depreciated | fraction | NA | U.S. Tax Code |
| OGFOR_OFF<br>OGINIT_OFF | XDCKAPOFF | XDCKAP | Offshore intangible drill costs that must be depreciated | fraction | NA | U.S. Tax Code |

| Parameters | | | | | |
|---|---|---|---|---|---|
| Appendix B Equation Number | Subroutine | Parameter Name | | Associated Variable | Classification |
| | | Code | Text | | |
| 1 | OGCST_L48 | ALPHA_DRL | ln(δ0) | Constant coefficient | 6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas) |
| 1 | OGCST_L48 | b0_DRL | ln(δ2) | Depth per well | Fuel (oil, shallow gas, deep gas) |
| 1 | OGCST_L48 | B1_DRL | ln(δ1) | Total onshore lower 48 wells drilled | Fuel (oil, shallow gas, deep gas) |
| 1 | OGCST_L48 | B2_DRL | ln(δ3) | Time trend - proxy for technology | Fuel (oil, shallow gas, deep gas) |
| 2 | OGCST_L48 | ALPHA_DRY | ln(δ0) | Constant coefficient | 6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas) |
| 2 | OGCST_L48 | B0_DRY | ln(δ2) | Depth per well | Fuel (oil, shallow gas, deep gas) |
| 2 | OGCST_L48 | B1_DRY | ln(δ1) | Total onshore lower 48 wells drilled | Fuel (oil, shallow gas, deep gas) |
| 2 | OGCST_L48 | B2_DRY | ln(δ3) | Time trend - proxy for technology | Fuel (oil, shallow gas, deep gas) |
| 3 | OGFOR_OFF | ALPHA_DRL_OFF | ln(δ0) | Constant coefficient | Fuel (oil, gas) |
| 3 | OGFOR_OFF | B0_DRL_OFF | ln(δ2) | Depth per well | Fuel (oil, gas) |
| 3 | OGFOR_OFF | B1_DRL_OFF | ln(δ1) | Offshore wells drilled in the Gulf of Mexico | NA |
| 3 | OGFOR_OFF | B2_DRL_OFF | ln(δ3) | Time trend - proxy for technology | Fuel (oil,gas) |
| 4 | OGFOR_OFF | ALPHA_DRL_OFF | ln(δ0) | Constant coefficient | Dry |
| 4 | OGFOR_OFF | B0_DRL_OFF | ln(δ2) | Depth per well | Dry |
| 4 | OGFOR_OFF | B1_DRL_OFF | ln(δ1) | Offshore wells drilled in the Gulf of Mexico | NA |
| 4 | OGFOR_OFF | B2_DRL_OFF | ln(δ3) | Time trend - proxy for technology | Dry |
| 5 | OGCST_L48 | ALPHA_LEQ | ln(ϵ0) | Constant coefficient | 6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas) |
| 5 | OGCST_L48 | b1_LEQ | ln(ϵ1) | Lower 48 successful wells by fuel (oil, gas) | Fuel (oil, shallow gas, deep gas) |
| 5 | OGCST_L48 | B2_LEQ | ln(ϵ2) | Time trend - proxy for technology | Fuel (oil, shallow gas, deep gas) |
| 6 | OGCST_L48 | ALPHA_OPR | ln(ϕ0) | Constant coefficient | 6 Lower 48 onshore regions; Fuel (oil, shallow gas, deep gas) |
| 6 | OGCST_L48 | B0_OPR | ln(ϕ2) | Depth per well | Fuel (oil, shallow gas, deep gas) |

| Parameters | | | | | |
|---|---|---|---|---|---|
| Appendix B Equation Number | Subroutine | Parameter Name | | Associated Variable | Classification |
| | | Code | Text | | |
| 6 | OGCST_L48 | B1_OPR | $\ln(\phi1)$ | Lower 48 successful wells by fuel (oil, gas) | Fuel (oil, shallow gas, deep gas) |
| 6 | OGCST_L48 | B2_OPR | $\ln(\phi3)$ | Time trend - proxy for technology | Fuel (oil, shallow gas, deep gas) |
| 92 | OGCOMP_AD | ALPHA_AD | $\ln(\alpha0)+\ln(\alpha1)$ | Constant coefficient plus regional dummy | Lower 48 regions (6 onshore, 3 offshore |
| 92 | OGCOMP_AD | BETA_AD | $\ln(\beta0)+\ln(\beta1)$ | Crude oil production plus regional dummy | Lower 48 regions (6 onshore, 3 offshore) |
| 117 | OGOUT_IMP | AWELLS1 | $-\rho * \beta0$ | Exploratory constant coefficient | NA |
| 117 | OGOUT_IMP | BWELLS1 | $-\rho * \beta1$ | Exploratory oil DCF coefficient | NA |
| 117 | OGOUT_IMP | CWELLS1 | $-\rho * \beta2$ | Exploratory dummy constant | NA |
| 117 | OGOUT_IMP | AWELLS2 | $-\rho * \beta0$ | Developmental constant coefficient | NA |
| 117 | OGOUT_IMP | BWELLS2 | $-\rho * \beta1$ | Developmental oil DCF coefficient | NA |
| 117 | OGOUT_IMP | CWELLS2 | $-\rho * \beta2$ | Developmental dummy constant | NA |
| 117 | OGOUT_IMP | RHOCAN(1) | $\rho$ | Exploratory auto correlation (Rho) | NA |
| 117 | OGOUT_IMP | RHOCAN(2) | $\rho$ | Developmental auto correlation (Rho) | NA |

**Outputs**

| OGSM Subroutine | Variable Name | Description | Unit | Classification | Passed To Module |
|---|---|---|---|---|---|
| OGFOR_AK<br>OGPIP_AK | OGANGTSMX | Maximum natural gas flow through ANGTS | BCF | NA | NGTDM |
| OGINIT_IMP | OGCNBLOSS | Gas lost in transit to border | BCF | 6 US/Canadian border crossings | NGTDM |
| OGINIT_IMP | OGCNCAP | Canadian capacities by border crossing | BCF | 6 US/Canadian border crossings | NGTDM |
| OGINIT_IMP<br>OGOUT_IMP | OGCNCON | Canada gas consumption | Oil: MMB<br>Gas: BCF | Fuel(oil,gas) | NGTDM |
| OGINIT_IMP | OGCNDMLOSS | Gas lost from wellhead to Canadian demand | BCF | NA | NGTDM |
| OGINIT_IMP | OGCNEXLOSS | Gas lost from US export to Canadian demand | BCF | NA | NGTDM |
| OGINIT_IMP | OGCNFLW | 1989 flow volumes by border crossing | BCF | 6 US/Canadian border crossings | NGTDM |
| OGINIT_IMP | OGCNPARM1 | Actual gas allocation factor | fraction | NA | NGTDM |
| OGINIT_IMP | OGCNPARM2 | Responsiveness of flow to different border prices | fraction | NA | NGTDM |
| OGINIT_IMP | OGCNPMARKUP | Transportation mark-up at border | 1987$ | 6 US/Canadian border crossings | NGTDM |
| OGINIT_RES<br>OGOUT_IMP | OGELSCAN | Canadian price elasticity | fraction | Fuel (oil, gas) | NGTDM |
| OGINIT_RES<br>OGOUT_L48<br>OGOUT_OFF | OGELSCO | Oil production elasticity | fraction | 6 Lower 48 onshore & 3 Lower 48 offshore regions | PMM |
| OGINIT_RES<br>OGOUT_OFF | OGELSNGOF | Offshore nonassociated dry gas production elasticity | fraction | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>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 |
| OGOUT_EOR | OGEORCOGG | Electric cogeneration volumes from EOR | MWH | 6 Lower 48 onshore regions | Industrial |
| OGCOMP_AD | OGPRDAD | Associated-dissolved gas production | BCF | 6 Lower 48 onshore regions & 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_IMP | OGPRRCAN | Canadian P/R ratio | fraction | Fuels (oil, gas) | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGPRRCO | Oil P/R ratio | fraction | 6 Lower 48 onshore & 3 Lower 48 offshore regions | PMM |

| Outputs | | | | | |
|---|---|---|---|---|---|
| **OGSM Subroutine** | **Variable Name** | **Description** | **Unit** | **Classification** | **Passed To Module** |
| OGINIT_RES<br>OGOUT_OFF | OGPRRNGOF | Offshore nonassociated dry gas P/R ratio | fraction | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGPRRNGON | Onshore nonassociated dry gas P/R ratio | fraction | 17 OGSM/NGTDM regions | NGTDM |
| OGFOR_AK<br>OGPIP_AK<br>OGPRO_AK | OGQANGTS | Gas flow at U.S. border from ANGTS | BCF | NA | NGTDM |
| OGCOMP_EMIS<br>OGOUT_EOR | OGQEORPR | Oil supply from EOR | MB | 6 Lower 48 onshore regions | PMM |
| OGINIT_IMP<br>OGOUT_IMP<br>OGOUT_MEX | OGQNGEXP | Natural gas exports | BCF | 6 US/Canada & 3 US/Mexico border crossings | NGTDM |
| OGLNG_OUT<br>OGOUT_IMP<br>OGOUT_MEX | OGQNGIMP | Natural gas imports | BCF | 3 US/Mexico border crossings; 4 LNG terminals | NGTDM |
| OGINIT_RES<br>OGOUT_IMP | OGRESCAN | Canadian end-of-year reserves | oil: MMB<br>gas: BCF | Fuel (oil, gas) | NGTDM |
| OGINIT_RES<br>OGOUT_L48<br>OGOUT_OFF | OGRESCO | Oil reserves | MMB | 6 Lower 48 onshore & 3 Lower 48 offshore regions | PMM |
| OGINIT_RES<br>OGOUT_OFF | OGRESNGOF | Offshore nonassociated dry gas reserves | BCF | 3 Lower 48 offshore regions | NGTDM |
| OGINIT_RES<br>OGOUT_L48 | OGRESNGON | Onshore nonassociated dry gas reserves | BCF | 17 OGSM/NGTDM regions | NGTDM |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| PARAM ( 1) | Operating cost overhead | Fraction | ICF Resources Incorporated<br>Various Industry Cost Surveys |
| PARAM ( 2) | G & A expenses on tangible and intangible investments | Fraction | ICF Resources Incorporated<br>Various Industry Cost Surveys |
| PARAM ( 3) | Useful life on capital investment | Years | Internal Revenue Service |
| PARAM ( 4) | Royalty rate on producer revenue | Fraction | Minerals Management Service |
| PARAM ( 5) | Severence tax rate | Fraction | Minerals Management Service |
| PARAM ( 6) | Income tax credit on capital investment | Fraction | Internal Revenue Service |
| PARAM ( 7) | Federal income tax rate | Fraction | Internal Revenue Service |
| PARAM ( 8) | Discount factor | Multiplier | ICF Resources Incorporated |
| PARAM ( 9) | Year after tangible investment begins depreciating | Years | Internal Revenue Service |
| PARAM (10) | Co-product value adjustment factor | Fraction | Minerals Management Service |
| PARAM (11) | Year in which costs are evaluated | | ICF Resources Incorporated |
| PARAM (12) | Current year in analysis | | ICF, EIA |
| PARAM (13) | Convergence criterion for method of bisection | Value | ICF Resources Incorporated |
| PARAM (14) | Fraction of investment costs that are tangible | Fraction | Definition |
| PARAM (15) | Fraction of exploratory well costs that are GNG costs | Fraction | Various Industry Cost Surveys |
| NPYR | Total number of years in production for wells in a given field size class | year | DOE Fossil Energy Models<br>ICF Resources Incorporated |
| ULT_PCT | Percent of ultimate recovery of a well that is produced each year | fraction | DOE Fossil Energy Models<br>ICF Resources Incorporated |
| NUSGS | US Geological Survey defined field size class number | | US Geological Survey |
| MIN_USGS | Minimum field size in a field size class defined by USGS | MMBOE | US Geological Survey |
| MAX_USGS | Maximum field size in a field size class defined by USGS | MMBOE | US Geological Survey |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| WEL_REC | Average per well ultimate recovery for fields in a USGS field size class | MMBOE | DOE Fossil Energy Models<br>ICF Resources Incorporated |
| PLAY_NUM | Unit code assigned to the 'plays' defined in DWOSS | | Minerals Management Service<br>ICF Resources Incorporated |
| PLAY_COD | Alpha-numeric code for the 'plays' defined in DWOSS | | ICF Resources Incorporated |
| PLAY_NAM | Description of the 'plays' defined in DWOSS | | ICF Resources Incorporated<br>Minerals Management Service |
| WAT_DEP | Average water depth for each of the water depth aggregated plays | feet | ICF Resources Incorporated<br>Offshore Data Services<br>Various Industry Sources |
| EXP_DEP | Average exploratory well drilling depth in each play | feet | Offshore Data Services<br>Minerals Management Service |
| DEV_DEP | Average development well drilling depth in each play | feet | Offshore Data Services<br>Minerals Management Service |
| EDSR | Exploration drilling success rate in each play | fraction | Offshore Data Services<br>Various Industry Sources<br>American Petroleum Institute |
| XDSR | Extension drilling success rate in each play | fraction | Offshore Data Services<br>Various Industry Sources<br>American Petroleum Institute |
| DDSR | Development drilling success rate in each play | fraction | Offshore Data Services<br>Various Industry Sources<br>American Petroleum Institute |
| GO_RATIO | Gas oil ratio for fields in each play | Scf/Bbl | Minerals Management Service |
| YIELD | Condensate yield for fields in each play | Bbl/MMcf | Minerals Management Service |
| APIGRAV | Crude oil gravity for fields in each play | Deg. API | Minerals Management Service |
| FLOWLINE | Length of gathering system for an average field in a play | Miles | Minerals Management Service<br>ICF Resources Incorporated |
| OIL_TARF | Transportation tariff for oil for an average field in a play | $/Bbl | Minerals Management Service |
| GAS_TARF | Transportation tariff for gas for an average field in a play | $/Mcf | Minerals Management Service |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| NPOOL | Number of fields in a play | | Minerals Management Service |
| OIL_GAS | The type of field - oil-bearing or gas-bearing | | ICF Resources Incorporated |
| OIL_SIZE | Size of the field if an oil-bearing field | MMBbl | Minerals Management Service |
| GAS_SIZE | Size of the field if an gas-bearing fieldBcfMinerals Management Service | | ICF Resources Incorporated |
| FSC | USGS Field Size Class to which the field belongs | | US Geological Survey |
| WDC | Gulf of Mexico water depth category to which the field belongs | | ICF Resources Incorporated<br>Minerals Management Service |
| EDRATE | Exploration drilling rate | feet/day | Various Industry Sources |
| DDRATE | Development drilling rate | feet/day | Various Industry Sources |
| ITECH | Five technology choices relating to exploration drilling rig, development drilling rig, pre-drilling, production structure, and pipeline construction | | Minerals Management Service<br>ICF Resources Incorporated<br>Various Literature Sources |
| EXPRIG | Exploration drilling rig | | Calculated in Model |
| PRERIG | Pre-drilling rig | | Calculated in Model |
| DEVRIG | Development drilling rig | | Calculated in Model |
| EXPWEL | Number of exploratory wells | | Calculated in Model |
| IYREXP | Year when exploratory drilling begins | | Calculated in Model |
| EXPTIM | Time required for exploratory drilling | | Calculated in Model |
| DELWEL | Number of delineation wells | | Calculated in Model |
| IYRDEL | Year when delineation drilling begins | | Calculated in Model |
| DELTIM | Time required for delineation drilling | | Calculated in Model |
| DEVWEL | Number of development wells | | Calculated in Model |
| DEVDRY | Number of dry development wells | | Calculated in Model |
| IYRDEV | Year when development drilling begins | | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| DEVTIM | Time required for development drilling | | Calculated in Model |
| PREDEV | Number of pre-drilled development wells | | Calculated in Model |
| PREDRY | Number of pre-drilled dry development wells | | Calculated in Model |
| IYRPRE | Year when pre-drilling begins | | Calculated in Model |
| PRETIM | Time required for pre-drilling | | Calculated in Model |
| NSLOT | Number of slots | | Calculated in Model |
| NSTRUC | Number of production structures | | Calculated in Model |
| IYRSTR | Year when structure installation begins | | Calculated in Model |
| STRTIM | Time required to complete the structure installation | | Calculated in Model |
| NTEMP | Number of templates | | Calculated in Model |
| IYRTEM | Year when template construction begins | | Calculated in Model |
| TEMTIM | Time required to complete the template installation | | Calculated in Model |
| IYRPIP | Year when the pipeline gathering system construction begins | | Calculated in Model |
| PIPTIM | Time required to complete the pipeline gathering system installation | | Calculated in Model |
| ULTREC | Cumulative ultimate recoverable reserves in a field | MMBOE | Calculated in Model |
| QAVOIL | Average oil production rate per year during the life of a field | Bbl | Calculated in Model |
| QOIL | Annual oil production volume for each year during the life of a field | Bbl | Calculated in Model |
| QCOIL | Cumulative oil production volume at the end of each year | Bbl | Calculated in Model |
| QAVGAS | Average gas production rate per year during the life of a field | Mcf | Calculated in Model |
| QGAS | Annual gas production volume for each year during the life of a field | Mcf | Calculated in Model |
| QCGAS | Cumulative gas production volume at the end of each year | Mcf | Calculated in Model |
| IYRPRD | Year when production begins in a field | | Calculated in Model |
| PRDTIM | Time required for total production | | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| MAXPYR | Year when the last well in a field ceases production | | Calculated in Model |
| IYRABN | Year when the field and production structure are abandoned | | Calculated in Model |
| GEOCST | Cost to conduct geological and geophysical evaluation | $ | Calculated in Model |
| DNCEXP | Cost to drill an exploratory well | $/well | Calculated in Model |
| DNCDEL | Cost to drill a delineation well | $/well | Calculated in Model |
| DNCDEV | Cost to drill a development well | $/well | Calculated in Model |
| DNCDRY | Cost to drill a dry development well | $/well | Calculated in Model |
| DNCPRE | Cost to drill a pre-drilled development well | $/well | Calculated in Model |
| DNCPDR | Cost to drill a pre-drilled dry development well | $/well | Calculated in Model |
| STRCST | Cost to construct and install the production structure | $/struc | Calculated in Model |
| TEMCST | Cost to construct and install the template | $/temp | Calculated in Model |
| ABNCST | Cost to abandon the production structure | $/struc | Calculated in Model |
| PIPECO | Cost to install pipeline and gathering system | $/struc | Calculated in Model |
| PRDEQP | Cost to install topside production equipment | $/struc | Calculated in Model |
| STROPC | Cost to operate the production structure | $/struc/year | Calculated in Model |
| GEO_CST | Annual geological and geophysical costs | $/year | Calculated in Model |
| GNG_CAP | Annual geological and geophysical costs that are capitalized | $/year | Calculated in Model |
| GNG_EXP | Annual geological and geophysical costs that are expensed | $/year | Calculated in Model |
| EXPDCST | Annual exploratory drilling costs | $/year | Calculated in Model |
| DELDCST | Annual delineation drilling costs | $/year | Calculated in Model |
| DEVDCST | Annual development drilling costs | $/year | Calculated in Model |
| DDRDCST | Annual dry development drilling costs | $/year | Calculated in Model |
| PREDCST | Annual pre-drilled development drilling costs | $/year | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| PDRDCST | Annual dry pre-drilled development drilling costs | $/year | Calculated in Model |
| PDEQCST | Annual production equipment and facilities costs | $/year | Calculated in Model |
| STRYCST | Annual structure installation costs | $/year | Calculated in Model |
| TMPYCST | Annual template installation costs | $/year | Calculated in Model |
| PIPECST | Annual pipeline and gathering system installation costs | $/year | Calculated in Model |
| ABNDCST | Annual abandonment costs | $/year | Calculated in Model |
| OPCOST | Annual total operating costs | $/year | Calculated in Model |
| TANG | Annual total tangible investment costs | $/year | Calculated in Model |
| INTANG | Annual total intangible investment costs | $/year | Calculated in Model |
| INVEST | Annual total capital investment costs | $/year | Calculated in Model |
| REV_OIL | Annual gross oil revenues | $/year | Calculated in Model |
| REV_GAS | Annual gross gas revenues | $/year | Calculated in Model |
| REV_GROS | Annual total producer revenues | $/year | Calculated in Model |
| GRAV_ADJ | Annual gravity adjustment penalties | $/year | Calculated in Model |
| TRAN_CST | Annual transportation costs for oil and gas | $/year | Calculated in Model |
| REV_ADJ | Annual adjusted gross revenues | $/year | Calculated in Model |
| ROYALTY | Annual royalty payments | $/year | Calculated in Model |
| REV_PROD | Annual net producer revenues | $/year | Calculated in Model |
| GNA_CST | Annual GNA on investments | $/year | Calculated in Model |
| GNA_OPN | Annual GNA on operations | $/year | Calculated in Model |
| REV_NET | Annual net Revenues from operations | $/year | Calculated in Model |
| NET_BTCF | Annual net before-tax cash flow | $/year | Calculated in Model |
| FED_TAXS | Annual federal tax bill | $/year | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| FED_INTC | Annual federal income tax credits | $/year | Calculated in Model |
| NET_INCM | Annual net income from operations | $/year | Calculated in Model |
| DEPR | Annual depreciation values | $/year | Calculated in Model |
| GNGRC | Annual GNG cost recovery | $/year | Calculated in Model |
| ANN_ATCF | Annual after-tax cash flow | $/year | Calculated in Model |
| NPV_ATCF | Annual discounted after-tax cash flow | $/year | Calculated in Model |
| REPCST | Replacement cost | $/BOE | Calculated in Model |
| NETPV | Net present value of the after-tax cash flow | $ | Calculated in Model |
| TYPE | Field type (oil or gas) transferred to the endogeneous component | | Calculated in Exogeneous Part |
| MASP_TOT | Minimum acceptable supply price transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| RSRV_OIL | Recoverable oil reserves transferrd to the endogeneous component | MMBbl | Calculated in Exogeneous Part |
| RSRV_GAS | Recoverable gas reserves transferred to the endogeneous component | Bcf | Calculated in Exogeneous Part |
| MASP_EXP | Exloration part of MASP transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| MASP_DRL | Drilling part of MASP transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| MASP_STR | Structure part of MASP transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| MASP_OPR | Operations part of MASP transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| EXPL_WEL | Number of exploratory wells transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| DEVL_WEL | Number of development wells transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| DRY_HOLE | Number of dry holes transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| STRUC_NO | Number of structures transferred to the endogeneous component | $/Bbl, $/Mcf | Calculated in Exogeneous Part |
| NREG | Number of deepwater Gulf of Mexico regions | | Minerals Management Service |
| NFUEL | Types of fuels in the model (oil and gas) | | EIA |
| NYEAR | Number of years analyzed for forecast | | EIA |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| VARIABLE | BRIEF DESCRIPTION | UNITS | SOURCE |
| RATIO_RP | Reserves to production ratio | | Minerals Management Service<br>ICF Resources Incorporated |
| WLDRLEVL | Drilling activity level constraint | Wells | Offshore Data Services<br>ICF Resources Incorporated |
| WLDRL_RT | Growth rate in drilling activity level | fraction | EIA, ICF |
| CUR_YEAR | Current year in the model | | EIA |
| RES_GROW | Growth rate for proved reserves | fraction | EIA, ICF |
| ADT_EXPL | Advanced technology multiplier for exploration costs | fraction | EIA, ICF |
| ADT_DRLG | Advanced technology multiplier for drilling costs | fraction | EIA, ICF |
| ADT_STRC | Advanced technology multiplier for structure costs | fraction | EIA, ICF |
| ADT_OPER | Advanced technology multiplier for operations costs | fraction | EIA, ICF |
| OILPRICE | Oil price in the analysis year | $/Bbl | PMM (NEMS) |
| GASPRICE | Gas price in the analysis year | $/Mcf | NGTDM (NEMS) |
| XPVD_OIL | Existing proved oil reserves in current year | MMBbl | Minerals Management Service<br>ICF Resources Incorporated |
| XPVD_GAS | Existing proved gas reserves in current year | Bcf | Minerals Management Service<br>ICF Resources Incorporated |
| XPVD_AGS | Existing proved associated gas reserves in current year | Bcf | Minerals Management Service<br>ICF Resources Incorporated |
| XPVD_CND | Existing proved condensate yield reserves in current year | MMBbl | Minerals Management Service<br>ICF Resources Incorporated |
| INFR_OIL | Inferred oil reserves (remaining economic) each year | MMBbl | Calculated in Model |
| INFR_GAS | Inferred gas reserves (remaining economic) each year | Bcf | Calculated in Model |
| INGR_AGS | Inferred associated gas reserves (remaining economic) each year | Bcf | Calculated in Model |
| INFR_CND | Inferred condensate reserves (remaining economic) each year | MMBbl | Calculated in Model |
| MSP_INFO | Average supply price for the inferred oil reserves each year | $/Bbl | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| **VARIABLE** | **BRIEF DESCRIPTION** | **UNITS** | **SOURCE** |
| MSP_INFG | Average supply price for the inferred gas reserves each year | $/Mcf | Calculated in Model |
| BKED_OIL | Oil reserves booked every year include reserve adds | MMBbl | Calculated in Model |
| BKED_GAS | Gas reserves booked every year include reserve adds | Bcf | Calculated in Model |
| BKED_AGS | Associated gas reserves booked every year include reserve adds | Bcf | Calculated in Model |
| BKED_CND | Condensate reserves booked every year include reserve adds | MMBbl | Calculated in Model |
| WEL_EXPO | Number of exploratory oil wells drilled each year | | Calculated in Model |
| WEL_DRYO | Number of dry holes oil wells drilled each year | | Calculated in Model |
| WEL_DEVO | Number of development oil wells drilled each year | | Calculated in Model |
| NUM_STRO | Number of oil production structures installed each year | | Calculated in Model |
| WEL_EXPG | Number of exploratory gas wells drilled each year | | Calculated in Model |
| WEL_DRYG | Number of dry holes oil wells drilled each year | | Calculated in Model |
| WEL_DEVG | Number of development gas wells drilled each year | | Calculated in Model |
| NUM_STRG | Number of gas production structures installed each year | | Calculated in Model |
| BEG_RESO | Beginning of the year proved oil reserves | MMBbl | Calculated in Model |
| BEG_RESG | Beginning of the year proved gas reserves | Bcf | Calculated in Model |
| GRO_RESO | Growth in proved oil reserves | MMBbl | Calculated in Model |
| GRO_RESG | Growth in proved gas reserves | Bcf | Calculated in Model |
| ADD_RESO | Reserve additions to proved oil reserves | MMBbl | Calculated in Model |
| ADD_RESG | Reserve additions to proved oil reserves | Bcf | Calculated in Model |
| PROD_OIL | Oil production | MMBbl | Calculated in Model |
| PROD_GAS | Gas production | Bcf | Calculated in Model |
| END_RSVO | End of the year oil reserves | MMBbl | Calculated in Model |
| END_RSVG | End of the year gas reserves | Bcf | Calculated in Model |

| DEEP WATER OFFSHORE SUPPLY SUBMODULE | | | |
|---|---|---|---|
| VARIABLE | BRIEF DESCRIPTION | UNITS | SOURCE |
| CST_EXPL | Annual exploration costs | MM$ | Calculated in Model |
| CST_DRLG | Annual drilling costs | MM$ | Calculated in Model |
| CST_STRC | Annual structure installation costs | MM$ | Calculated in Model |
| CST_OPER | Annual operating costs | MM$ | Calculated in Model |

# Appendix B.  Mathematical Description

# Calculation of Costs

## Estimated Wells

*Onshore*

$$ESTWELLS_t = \exp(b0) * \exp(b1 * \log(POIL_t) * \log(PGAS_t)) \qquad (1)$$

*Offshore*

$$GOMWELLS_t = \exp(\alpha) * \exp(\beta * \log(POIL_t) * \log(PGAS_t)) \qquad (2)$$

## Lower 48 Rigs

*Onshore*

$$RIGSL48_t = \exp(b0) * RIGSL48_{t-1}^{b1} * REVRIG_{t-1}^{b2} \qquad (3)$$

*Offshore*

$$RIGSOFF_t = \exp(\alpha) * RIGSOFF_{t-1}^{\beta} * REVRIG_{t-2}^{\gamma} \qquad (4)$$

## Drilling Costs

*Onshore*

$$\begin{aligned} DRILLCOST_{r,k,t} = {} & \exp(\ln(\delta 0)_{r,k}) * \exp(\ln(\delta 1)_{d,k}) * \exp(\ln(\delta 2)_{r,k}) * ESTWELLS_t^{\delta 3_k} * RIGSL48_t^{\delta 4_k} * \exp(\delta 5_k * TIME_t) * \\ & DRILLCOST_{r,k,t-1}^{\rho_k} * \exp(-\rho_k * \ln(\delta 0)_{r,k}) * \exp(-\rho_k * \ln(\delta 1)_{d,k}) * \exp(-\rho_k * \ln(\delta 2)_{r,k}) * \\ & ESTWELLS_{t-1}^{-\rho_k * \delta 3_k} * RIGSL48_{t-1}^{-\rho_k * \delta 4_k} * \exp(-\rho_k * \delta 5_k * TIME_{t-1}) \end{aligned} \qquad (5)$$

$$\begin{aligned} DRYCOST_{r,k,t} = {} & \exp(\ln(\delta 0)_{r,k}) * \exp(\ln(\delta 1)_{d,k}) * \exp(\ln(\delta 2)_{r,k}) * ESTWELLS_t^{\delta 3_k} * RIGSL48_t^{\delta 4_k} * \exp(\delta 5_k * TIME_t) * \\ & DRYCOST_{r,k,t-1}^{\rho_k} * \exp(-\rho_k * \ln(\delta 0)_{r,k}) * \exp(-\rho_k * \ln(\delta 1)_{d,k}) * \exp(-\rho_k * \ln(\delta 2)_{r,k}) * \\ & ESTWELLS_{t-1}^{-\rho_k * \delta 3_k} * RIGSL48_{t-1}^{-\rho_k * \delta 4_k} * \exp(-\rho_k * \delta 5_k * TIME_{t-1}) \end{aligned} \qquad (6)$$

*Offshore*

$$DRILLCOST_k = \exp(\delta 0_k) * GOMWELLS_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * RIGSOFF_{t-2}^{\delta 3_k} * \exp(\delta 4_k * TIME_t) \qquad (7)$$

$$DRYCOST_k = \exp(\delta 0_k) * GOMWELLS_t^{\delta 1_k} * \exp(\delta 2_{d,k}) * RIGSOFF_{t-2}^{\delta 3_k} * \exp(\delta 4_k * TIME_t) \qquad (8)$$

## Lease equipment costs

$$LEQC_{r,k,t} = \exp(\ln(\epsilon 0)_{r,k}) * \exp(\ln(\epsilon 1)_k * DEPTH_{r,k,t}) * ESUCWELL_{k,t}^{\epsilon 2_k} * \exp(\epsilon 3_k * TIM$$
$$\exp(-\rho_k * \ln(\epsilon 0)_{r,k}) * \exp(-\rho_k * \ln(\epsilon 1)_k * DEPTH_{r,k,t-1}) * ESUCWELL_{k,t-1}^{-\rho_k * \epsilon 2} \qquad (9)$$

### Operating Costs

$$OPC_{r,k,t} = \exp(\ln(\epsilon 0)_{r,k}) * \exp(\ln(\epsilon 1)_k * DEPTH_{r,k,t}) * ESUCWELL_{k,t}^{\epsilon 2_k} * \exp(\epsilon 3_k * TIMI$$
$$\exp(-\rho_k * \ln(\epsilon 0)_{r,k}) * \exp(-\rho_k * \ln(\epsilon 1)_k * DEPTH_{r,k,t-1}) * ESUCWELL_{k,t-1}^{-\rho_k * \epsilon 2_k} \qquad (10)$$

## Discounted Cash Flow Algorithm

### Expected discounted cash flow

$$PROJDCF_{i,r,k,t} = (PVREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP - PVKAP - PVOPERCOST - PVABANDON - PVSIT - PVFIT)_{i,r,k,t} \qquad (11)$$

### Present value of expected revenues

$$PVREV_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ Q_{r,k,T} * \lambda * (P_{r,k,T} - TRANS_{r,k}) * \left[\frac{1}{1+disc}\right]^{T-t} \right], \ \lambda = \begin{cases} 1 & \text{if primary fuel} \\ COPRD & \text{if secondary fuel} \end{cases} \qquad (12)$$

### Present value of expected royalty payments

$$PVROY_{i,r,k,t} = ROYRT * PVREV_{i,r,k,t} \qquad (13)$$

### Present value of expected production taxes

$$PVPRODTAX_{i,r,k,t} = PVREV_{i,r,k,t} * (1 - ROYRT) * PRODTAX_{r,k} \qquad (14)$$

### Present value of expected costs

*Drilling costs*

$$PVDRILLCOST_{i,r,k,t} = \sum_{T=t}^{t+n} \Big[ \big[ DRILL_{1,r,k,t} * SR_{1,r,k} * WELL_{1,k,T} + DRILL_{2,r,k,t} * SR_{2,r,k} * WELL_{2,k,T} + DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,T} + DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,T} \big] * \left(\frac{1}{1 + disc}\right)^{T-t} \Big] \qquad (15)$$

*Lease equipment costs*

$$PVEQUIP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ EQUIP_t * \left( SR_{1,r,k} * WELL_{1,k,T} + SR_{2,r,k} * WELL_{2,k,T} \right) * \left[\frac{1}{1 + disc}\right]^{T-t} \right] \qquad (16)$$

*Capital costs*

$$PVKAP_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ KAP_{i,r,k,T} * \left[ \frac{1}{1 + disc} \right]^{T-t} \right] \tag{17}$$

*Operating costs*

$$PVOPERCOST_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ OPCOST_{i,r,k,t} * \sum_{k=1}^{T} \left[ SR_{1,r,k} * WELL_{1,k,T} + SR_{2,r,k} * WELL_{2,k,T} \right] * \left( \frac{1}{1 + disc} \right)^{T-t} \right] \tag{18}$$

*Abandonment costs*

$$PVABANDON_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ COSTABN_{i,r,k} * \left[ \frac{1}{1 + disc} \right]^{T-t} \right] \tag{19}$$

**Present value of expected tax base**

$$PVTAXBASE_{i,r,k,t} = \sum_{T=t}^{t+n} \left[ (REV - ROY - PRODTAX - OPERCOST - ABANDON - XIDC - AIDC - DEPREC - DHC)_{i,r,k,t} * \left( \frac{1}{1 + disc} \right)^{T-t} \right]$$

**Expected expensed costs**

$$XIDC_{i,r,k,t} = DRILL_{1,r,k,t} * (1 - EXKAP) * (1 - XDCKAP) * SR_{1,r,k} * WELL_{1,k,t} + DRILL_{2,r,k,t} * (1 - DVKAP) * (1 - XDCKAP) * SR_{2,r,k} * WELL_{2,k,t} \tag{21}$$

**Expected dry hole costs**

$$DHC_{i,r,k,t} = DRY_{1,r,k,t} * (1 - SR_{1,r,k}) * WELL_{1,k,t} + DRY_{2,r,k,t} * (1 - SR_{2,r,k}) * WELL_{2,k,t} \tag{22}$$

**Expected depreciable costs**

$$DEPREC_{i,r,k,t} = \sum_{j=\beta}^{t} \left[ \left[ (DRILL_{1,r,k,T} * EXKAP + EQUIP_{1,r,k,T}) * SR_{1,r,k} * WELL_{1,k,j} + (DRILL_{2,r,k,T} * DVKAP + EQUIP_{2,r,k,T}) * SR_{2,r,k} * WELL_{2,k,j} + KAP_{r,k,j} \right] * DEP_{t-j+1} * \left( \frac{1}{1 + infl} \right)^{t-j} * \left( \frac{1}{1 + disc} \right)^{t-j} \right], \tag{23}$$

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

**Present value of expected state income taxes**

$$PVSIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * STRT \tag{24}$$

**Present value of expected federal income taxes**

$$PVFIT_{i,r,k,t} = PVTAXBASE_{i,r,k,t} * (1 - STRT) * FDRT \tag{25}$$

**Discounted cash flow for a representative developmental well**

$$DCF_{2,r,k,t} = PROJDCF_{2,r,k,t} * SR_{2,r,k} \tag{26}$$

**Discounted cash flow for a representative exploratory well**

$$DCF_{1,r,k,t} = PROJDCF_{1,r,k,t} * SR_{1,r,k} \tag{27}$$

## Lower 48 Onshore & Offshore Expenditures and Well Determination

**Share of unconventional gas wells**

$$w_{i,r,k,t} = WELLS_{i,r,k,t-1} / \sum_{k} WELLS_{i,r,k,t-1}, \quad \text{for } k = 4,\ 5,\ 6 \tag{28}$$

**Expected DCF for unconventional gas recovery**

$$UGDCFON_{i,r,t} = \sum_{k=4}^{6} w_{i,r,k,t} DCFON_{i,r,k,t}, \quad \text{for } i = 1{,}2,\ r = 1{,}2{,}3{,}4{,}5 \tag{29}$$

**Regional expected discounted cash flow**

$$RDCFON_{i,r,t} = \sum_{k} w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i = 1,\ 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{30}$$

$$RDCFOFF_{i,r,t} = \sum_{k} w_{i,r,k,t} * DCFOFF_{i,r,k,t}, \quad \text{for } i = 1,\ 2,\ r = \text{offshore regions},\ k = 1,\ 2 \tag{31}$$

**Regional share of total wells**

$$w_{i,r,t} = WELLS_{i,r,t-1} / \sum_{r} WELLS_{i,r,t-1}, \quad \text{for each } i,\ r \tag{32}$$

**Regional oil/shallow gas expected discounted cash flow**

$$OSGDCFON_{i,r,t} = \sum_{k=1}^{z} w_{i,r,k,t} * DCFON_{i,r,k,t}, \quad \text{for } i=1,\ r,\ k=1{,}2 \tag{33}$$

**Regional oil/shallow gas share of oil and shallow gas wells**

$$w_{i,r,k,t} = WELLSON_{i,r,k,t-1} / \sum_{k=1}^{z} WELLSON_{i,r,k,t-1}, \quad \text{for } i=1,\ r,\ k=1{,}2 \tag{34}$$

## Lower 48 Onshore Well Forecasting Equations

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DCFON_{i,r,k,t-2} + m3_{i,r,k} * DUM86_t \quad (35)$$
$$i=1,\ r=1,\ k=1$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM81_t + m3_{i,r,k} * \quad (36)$$
$$i=1,\ r=1,\ k=2$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t \quad (37)$$
$$i=2,\ r=1,\ k=1$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM81_t + m3_{i,r,k} * DUM86_t \quad (38)$$
$$i=2,\ r=1,\ k=2$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM86_t + m3_{i,r,k} * DUMYR81_t) * SHARE_{i,r,k} \quad (39)$$
$$i=1,\ r=1,\ k=4,5,6$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t) * SHARE_{i,r,k} \quad (40)$$
$$i=2,\ r=1,\ k=4,5,6$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1}) \end{aligned} \quad (41)$$
$$i=1,\ r=2,\ k=1$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & \exp(m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1})) \\ & * (WELLSON_{i,r,k,t-1} ** \rho_{i,r,k}) \end{aligned} \quad (42)$$
$$i=1,\ r=2,\ k=2$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DCFON_{i,r,k,t-1} + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DCFON_{i,r,k,t-2}) \end{aligned} \quad (43)$$
$$i=1,\ r=2,\ k=3$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_{t-1}) \end{aligned} \quad (44)$$
$$i=2,\ r=2,\ k=1$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM7879_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM7879_{t-1}) \end{aligned} \quad (45)$$
$$i=2,\ r=2,\ k=2$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} \quad (46)$$
$$i=2,\ r=2,\ k=3$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t}) * SHARE_{i,r,k} \quad (47)$$
$$i=1,\ r=2,\ k=4,6$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM89_t) * SHARE_{i,r,k} \quad i=2,\ r=2,\ k=4,6 \tag{48}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1}) \\ & i=1,\ r=3,\ k=1 \end{aligned} \tag{49}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t} + m2_{i,r,k} * DUM7879_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM7879_{t-1}) \\ & i=1,\ r=3,\ k=2 \end{aligned} \tag{50}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t \\ & (i=1,\ (r=3,\ k=3) \end{aligned} \tag{51}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * RDCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM8084_t + m3_{i,r,k} * DUM86_t \\ & + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * RDCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM8084_{t-1} m3_{i,r,k} * DUM64_{t-1}) \\ & i=2,\ r=3,\ k=1 \end{aligned} \tag{52}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM7882_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM7882_{t-1}) \\ & i=2,\ r=3,\ k=2 \end{aligned} \tag{53}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUMYR82_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUMYR82_{t-1}) \\ & i=2,\ r=3,\ k=3 \end{aligned} \tag{54}$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM90_t) * SHARE_{i,r,k} \quad i=2,\ r=3,\ k=4,6 \tag{55}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1}) \\ & i=1,\ r=4,\ k=1 \end{aligned} \tag{56}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM85_t) \quad i=1,\ r=4,\ k=2 \tag{57}$$

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1}) \\ & i=1,\ r=4,\ k=3 \end{aligned} \tag{58}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM86_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1}) \quad i=2,\ r=4,\ k=1 \tag{59}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM7882_t + m3_{i,r,k} * DUM86_t + m4_{i,r,k} * DUM9093_t \quad i=2,\ r=4,\ k=2 \tag{60}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM8385_t + m3_{i,r,k} * DUM86_t \quad i=2,\ r=4,\ k=3 \tag{61}$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM90_t + m3_{i,r,k} * DUMYR82_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM86_{t-1} + m3_{i,r,k} * DUMYR82_{t-1})) * SHARE_{i,r,k} \quad i=2,\ r=4,\ k=4,6 \tag{62}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM86_t \quad i=1,\ r=5,\ k=1 \tag{63}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t} + m2_{i,r,k} * DUM82_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * OSGDCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM82_{t-1}) \quad i=1,\ r=5,\ k=2 \tag{64}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM86_t \quad i=1,\ r=5,\ k=3 \tag{65}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM86_t \quad i=2,\ r=5,\ k=1 \tag{66}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM8389_t + m3_{i,r,k} * DUM9093_t + m4_{i,r,k} * DUMYR94_t \quad i=2,\ r=5,\ k=2 \tag{67}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM92_t \quad i=2,\ r=5,\ k=3 \tag{68}$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM9091_t + m3_{i,r,k} * DUM9293_t) * SHARE_{i,r,k} \quad i=1,\ r=5,\ k=4,6 \tag{69}$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM83_t + m3_{i,r,k} * DUM83_t) * SHARE_{i,r,k} \quad i=2,\ r=5,\ k=4,6 \tag{70}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DUM8392_t + m3_{i,r,k} * DUM93_t + m4_{i,r,k} * TREND7782_t \quad i=1,\ r=6,\ k=1 \tag{71}$$

$$WELLSON_{i,r,k,t} = (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM83_t + m3_{i,r,k} * DUMYR94_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM83_{t-1} + m3_{i,r,k} * DUMYR94_{t-1}) \quad i=1,\ r=6,\ k=2 \tag{72}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t} + m2_{i,r,k} * DCFON_{i,r,k,t-1} + m3_{i,r,k} * DUM92_t \quad i=2,\ r=6,\ k=1 \tag{73}$$

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-1} + m2_{i,r,k} * DUM8485_t + m3_{i,r,k} * DUM93_t + \rho_{i,r,k} * WELLSON_{i,r,k,t-1} - \rho_{i,r,k} * (m0_{i,r,k} + m1_{i,r,k} * DCFON_{i,r,k,t-2} + m2_{i,r,k} * DUM8485_{t-1} + m3_{i,r,k} * DUM93_{t-1}) \quad i=2,\ r=6,\ k=2 \tag{74}$$

## Lower 48 Offshore Well Forecasting Equations

$$WELLSOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t} + \alpha2_{i,r,k} * DUM86_t \quad i=2,\ r=2,\ k=1 \tag{75}$$

$$WELLSOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t-1} + \alpha2_{i,r,k} * DUMYR82_t + \rho_{i,r,k} * WELLSOFF_{i,r,k,t-1} - \rho_{i,r,k} * (0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t-2} + \alpha2_{i,r,k} * DUMYR82_{t-1}) \quad i=1,\ r=5,\ k=1 \tag{76}$$

$$WELLSOFF_{i,r,k,t} = \exp\ (\alpha0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t-1} + \alpha2_{i,r,k} * DUM83_t) \quad i=2,\ r=5,\ k=1 \tag{77}$$

$$WELLSOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t} + \alpha2_{i,r,k} * DUM7681_t \quad i=1,\ r=5,\ k=2 \tag{78}$$

$$WELLSOFF_{i,r,k,t} = \exp\ (\alpha0_{i,r,k} + \alpha1_{i,r,k} * DCFOFF_{i,r,k,t}) \quad i=2,\ r=5,\ k=2 \tag{79}$$

## Calculation of successful onshore wells

$$SUCWELSON_{i,r,k,t} = WELLSON_{i,r,k,t} * SR_{i,r,k},\ \text{for } i = 1,\ 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{80}$$

## Calculation of onshore dry holes

$$DRYWELON_{i,r,k,t} = WELLSON_{i,r,k,t} - SUCWELSON_{i,r,k,t},\ \text{for } i = 1,\ 2,\ r = \text{onshore regions},\ k = 1 \text{ thru } 6 \tag{81}$$

### Calculation of successful offshore wells

$$SUCWELSOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} * SR_{i,r,k}, \text{ for } i = 1, 2, r = \text{offshore regions}, k = 1, 2 \tag{82}$$

### Calculation of offshore dry holes

$$DRYWELOFF_{i,r,k,t} = WELLSOFF_{i,r,k,t} - SUCWELSOFF_{i,r,k,t}, \text{ for } i = 1, 2, \\ r = \text{offshore regions}, k = 1, 2 \tag{83}$$

## Lower 48 Onshore & Offshore Reserve Additions

### New reserve discoveries

$$FR1_{r,k,t} = FR1_{r,k,t-1} * e^{-\delta 1_{r,k,t} * SW1_{r,k,t}} \tag{84}$$

$$\delta 1_{r,k,t} = \frac{(FR1_{r,k,t-1} - FRMIN_{r,k}) * RSVGR}{QTECH_{r,k,t} - CUMRES1_{r,k,t-1}} \tag{85}$$

$$CUMRES1_{r,k,t} = \sum_{T=1}^{t} (NRD_{r,k,T} * RSVGR) \tag{86}$$

$$NDR_{r,k,t} = \frac{FR1_{r,k,t-1}}{\delta 1_{r,k,t}} * \left(1 - e^{-\delta 1_{r,k,t} * SW1}\right) \tag{87}$$

*Inferred reserves*

$$I_{r,k,t} = NDR_{r,k,t} * (RSVGR - 1) \tag{88}$$

### Reserve revisions

$$FR2_{r,k,t} = FR2_{r,k,t-1} * e^{-\delta 2_{r,k,t} * SW2_{r,k,t}} \tag{89}$$

$$\delta 2_{r,k,t} = \frac{FR2_{r,k,t-1} * DECFAC}{I_{r,k} * (1 + TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}} \tag{90}$$

$$CUMRES2_{r,k,t} = \sum_{T=1}^{t} I_{r,k,T} \tag{91}$$

$$REV_{r,k,t} = \frac{FR2_{r,k,t-1}}{\delta 2_{r,k,t}} * \left(1 - e^{-\delta 2_{r,k,t} * SW2}\right) \tag{92}$$

### Reserve extensions

$$FR3_{r,k,t} = FR3_{r,k,t-1} * e^{-\delta 3_{r,k,t} * SW3_{r,k,t}} \tag{93}$$

$$\delta 3_{r,k,t} = \frac{FR3_{r,k,t-1} * DECFAC}{I_{r,k} * (1+TECH)^{t-T} + CUMRES2_{r,k,t-1} - CUMRES3_{r,k,t-1}} \tag{94}$$

$$CUMRES3_{r,k,t} = \sum_{T=1}^{t} (EXT_{r,k,T} + REV_{r,k,T}) \tag{95}$$

$$EXT_{r,k,t} = \frac{FR3_{r,k,t-1}}{\delta 3_{r,k,t}} * \left(1 - e^{-\delta 3_{r,k,t} * SW3}\right) \tag{96}$$

**Total reserve additions**

$$RA_{r,k,t} = \frac{1}{X_{r,k}} \int_0^{SW1_{r,k,t}} FR1_{r,k,t} d(SW1) + \int_0^{SW2_{r,k,t}} FR2_{r,k,t} d(SW2) + \int_0^{SW3_{r,k,t}} FR3_{r,k,t} d(SW3) \tag{97}$$

**End-of-year reserves**

$$R_{r,k,t} = R_{r,k,t-1} - Q_{r,k,t} + RA_{r,k,t} \tag{98}$$

## Lower 48 Onshore & Offshore Production to Reserves Ratio

Option 1

$$PR_{t+1} = \frac{(R_{t-1} * PR_t * (1 - PR_t)) + (PRNEW * RA_t)}{R_t} \tag{99}$$

$$Q_{r,k,t+1} = [R_{r,k,t}] * [PR_{r,k,t} * (1 + \beta_{r,k} * \Delta P_{r,k,t+1})] \qquad (100$$

Options 2 and 3

$$PR_{r,k,t} = \frac{X_{r,k,t}}{1 + X_{r,k,t}} \tag{101}$$

where,

for natural gas option 2

$$X_{r,k,t} = \exp((1-\rho gas)*cgas_r) * \exp(h*CARRIAGE_t) * \exp(-\rho gas*h*CARRIAGE_{t-1})* \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * PGAS_{r,t}^{\alpha} * PGAS_{r,t-1}^{-\rho gas*\alpha} \tag{102}$$

for crude oil option 2

$$X_{r,k,t} = \exp((1-\rho oil)*coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \exp(\beta*POIL_{r,t}) * \exp(-\rho oil*\beta*POIL_{r,t-1}) \tag{103}$$

for natural gas option 3

$$X^{\circ}_{r,k,t} = \exp((1-\rho gas)*cgas_r) * \exp(h*CARRIAGE_t) * \exp(-\rho gas*h*CARRIAGE_{t-1})* \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho gas} * \exp(fgas_r*RA_{r,k,t-1}) * \exp(-\rho gas*fgas_r*RA_{r,k,t-2}) \tag{104}$$

for crude oil option 3

$$X^{\circ}_{r,k,t} = \exp((1-\rho oil)*coil_r) * \left(\frac{PR_{r,k,t-1}}{1-PR_{r,k,t-1}}\right)^{\rho oil} * \exp(\beta*POIL_{r,t}) * \exp(-\rho oil*\beta*POIL_{r,t-1}) * \exp(foil_r*RA_{r,k,t-1}) * \exp(-\rho oil*foil_r*RA_{r,k,t-2}) \tag{105}$$

## Associated-dissolved gas production

$$ADGAS_{r,t} = e^{\ln(\alpha 0)_r + \ln(\alpha 1)_r*DUM86_t} * OILPROD_{r,t}^{\beta 0_r + \beta 1_r*DUM86_t} \tag{106}$$

## Alaska Supply

### Expected Costs

*Drilling costs*

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1)**(t-T_b) \tag{107}$$

*Lease equipment costs*

$$EQUIP_{r,k,t} = EQUIP_{r,k,T_b} * (1 - TECH2)**(t - T_b) \tag{108}$$

*Operating costs*

$$OPCOST_{r,k,t} = OPCOST_{r,k,T_b} * (1 - TECH3)**(t - T_b) \tag{109}$$

*Tariffs*

$$TRR_t = OPERCOST_t + DRR_t + TOTDEP_t + MARGIN_t + DEFRETREC_t + TXALLW_t \\ NONTRANSREV_t + CARRYOVER_t \tag{110}$$

$$TOTDEP_t = DEP_t * \left(DEPPROP_{t-2} + ADDS_{t-1} - PROCEEDS_{t-1} - TOTDEP_{t-1}\right) \tag{111}$$

$$MARGIN_t = ALLOW_t * THRUPUT_t + 0.064 * \left(DEPPROP_{NEW,t} + DEFRET_{NEW,t} - DEFTAX_{NEW,t}\right) \tag{112}$$

$$DEFRETREC_t = DEP_t * \left(DEFRET_{t-2} + INFLADJ_{t-1} + AFUDC_{t-1} - DEFRETREC_{t-1}\right) \tag{113}$$

$$TXALLW_t = TXRATE * \left(MARGIN_t + DEFRETREC_t\right) \tag{114}$$

## Canadian Gas Trade

### Net cash flow

$$NCF_{i,k,T} = (REV - ROY - DRILLCOST - EQUIPCOST - \\ OPERCOST - DRYCOST - PROVTAX - FEDTAX)_{i,k,T} \tag{115}$$

### Expected discounted cash flow

$$PROJDCF_{i,k,t} = \sum_{T=t}^{t+n} \left[ NCF_{i,k,T} * \left[\frac{1}{1+disc}\right]^{T-t} \right] \tag{116}$$

### Expected revenues

$$REV_{i,k,t} = Q_{k,t} * (P_{k,t} - TRANS_k) + Q_{COP,t} * (P_{COP,t} - TRANS_{COP}), \quad COP = coproduct \tag{117}$$

### Expected royalty payments

$$ROY_{i,k,t} = ROYRT * REV_{i,k,t} \tag{118}$$

### Expected costs

*Successful drilling costs*

$$DRILLCOST_{i,k,t} = DRILL_{1,k,t} * SR_{1,k} * WELL_{1,k,T} + DRILL_{2,k,t} * SR_{2,k} * WELL_{2,k,T} \tag{119}$$

*Dry hole costs*

$$DRYCOST_{i,k,t} = DRY_{1,k,t} * (1 - SR_{1,k}) * WELL_{1,k,T} + DRY_{2,k,t} * (1 - SR_{2,k}) * WELL_{2,k,T} \tag{120}$$

*Lease equipment costs*

$$EQUIP_{i,k,t} = EQUIP_t * \left(SR_{1,k} * WELL_{1,k,T} + SR_{2,k} * WELL_{2,k,T}\right) \tag{121}$$

*Operating costs*

$$OPERCOST_{i,k,t} = OPCOST_{i,k,t} * \sum_{k=1}^{T} \left[SR_{1,k} * WELL_{1,k,T} + SR_{2,k} * WELL_{2,k,T}\right] \tag{122}$$

**Expected federal tax base**

$$FIT_{i,k,t} = (REV - OPERCOST - XIDC - DEPREC - RA - DA - DRYCOST)_{i,k,t} \tag{123}$$

**Expected expensed costs**

$$XIDC_{i,k,t} = DRILL_{1,k,t} * EXP_1 * SR_{1,k} * WELL_{1,k,t} + DRILL_{2,k,t} * EXP_2 * SR_{2,k} * WELL_{2,k,t} \tag{124}$$

**Expected depreciable costs**

$$\begin{aligned} DEPREC_{i,k,t} = \sum_{j=\beta}^{t} \Big[ & \big[(DRILL_{1,k,T} * (1 - EXP_1) + EQUIP_{1,k,T}) * SR_{1,k} * WELL_{1,k,j} + \\ & (DRILL_{2,k,T} * (1 - EXP_2) + EQUIP_{2,k,T}) * SR_{2,k} * WELL_{2,k,j}\big] * \\ & DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j}\Big], \\ & \beta = \begin{cases} T \text{ for } t \le T+m-1 \\ t-m+1 \text{ for } t > T+m-1 \end{cases} \end{aligned} \tag{125}$$

**Expected resource allowance**

$$RA_{i,k,t} = 0.25 * (REV_{i,k,t} - ROY_{i,k,t} - OPERCOST_{i,k,t} - DEPREC_{i,k,t}) \tag{126}$$

**Expected depletion allowance**

$$DA_{i,k,t} = (DRILLCOST_{i,k,t} + DRYCOST_{i,k,t}) * (1 - INVESTCR) * DEPLRT \tag{127}$$

**Expected provincial tax base**

$$PTI_{i,k,t} = FTI_{i,k,t} - ROY_{i,k,t} - RA_{i,k,t} - DRYCOST_{i,k,t} \tag{128}$$

**Expected provincial income taxes**

$$PROVTAX_{i,k,t} = FTI_{i,k,t} * PROVRT \tag{129}$$

**Expected federal income taxes**

$$FEDTAX_{i,k,t} = FTI_{i,k,t} * FDRT \tag{130}$$

**Calculation of successful Canadian wells**

$$WELLS_{k,t} = \beta 0_k + \beta 1_k * DCF_{k,t} + \beta 2_k * DUM83_t + \rho_k * WELLS_{k,t-1} - \rho_k * \beta 0_k - \rho_k * \beta 1_k * DCF_{k,t-1} - \rho_k * \beta 2_k * DUM83_{t-1}, \text{ for } k = \text{oil, gas} \quad (131)$$

### Reserve additions

$$FR_{k,t} = FR_{k,t-1} * e^{-\delta_{k,t} * WELLS_{k,t}} * (1 + FRTECH_k) \quad (132)$$

$$\delta_{k,t} = \frac{(FR_{k,t-1} - FRMIN_k) * RSVGR}{Q_k * (1.0 + TECH)^{t-T} - CUMRES_{k,t-1}} \quad (133)$$

$$RA_{k,t} = \frac{FR_{k,t-1}}{\delta_{k,t}} * (1 - e^{-\delta_{k,t} * WELLS_{k,t}}) \quad (134)$$

$$CUMRES_{k,t} = \sum_{T=1}^{t} RA_{k,T} \quad (135)$$

### End-of-year reserves

$$R_{k,t} = R_{k,t-1} + RA_{k,t} - Q_{k,t} \quad (136)$$

### Production to reserves ratio

$$PR_{k,t+1} = \frac{Q_{k,t} * (1 - PR_{k,t}) + PRNEW * RA_{k,t}}{R_{k,t}} \quad (137)$$

## Deep Water Offshore Supply

### COSTING AND CASH-FLOW ROUTINES

### Geological and Geophysical Costs Per Year:

$$GNG\_CAP_t = \frac{GNGCAP}{GNG\_TIM}, \ t = IYREXP \text{ to } (IYREXP + GNG\_TIM - 1) \quad (138)$$

$$GNG\_EXP_t = \frac{GNGEXP}{GNG\_TIM}, \ t = IYREXP \text{ to } (IYREXP + GNG\_TIM - 1) \quad (139)$$

### Exploration Drilling Costs Per Year

$$EXPDCST_t = DNCEXP * \frac{EXPWEL}{EXPTIM}, \ t = IYREXP \text{ to } (IYREXP + EXPTIM - 1) \quad (140)$$

**Delineation Drilling Costs Per Year**

$$\mathrm{DELDCST}_t = \mathrm{DNCDEL} * \frac{\mathrm{DELWEL}}{\mathrm{DELTIM}},\ t = \mathrm{IYRDEL}\ \text{to}\ (\mathrm{IYRDEL} + \mathrm{DELTIM} - 1) \tag{141}$$

**Pre-drilled Development Well Costs Per Year**

$$\mathrm{PREDCST}_t = \mathrm{DNCPRE} * \frac{\mathrm{PREDEV}}{\mathrm{PRETIM}},\ t = \mathrm{IYRPRE}\ \text{to}\ (\mathrm{IYRPRE} + \mathrm{PRETIM} - 1) \tag{142}$$

**Pre-drilled Dry Development Well Costs Per Year**

$$\mathrm{PDRDCST}_t = \mathrm{PREDRY} * \frac{\mathrm{DELWEL}}{\mathrm{PRETIM}},\ t = \mathrm{IYRPRE}\ \text{to}\ (\mathrm{IYRPRE} + \mathrm{PRETIM} - 1) \tag{143}$$

**Development Drilling Costs Per Year**

$$\mathrm{DEVDCST}_t = \mathrm{DNCDEV} * \frac{\mathrm{DEVWEL}}{\mathrm{DEVTIM}},\ t = \mathrm{IYRDEV}\ \text{to}\ (\mathrm{IYRDEV} + \mathrm{DEVTIM} - 1) \tag{144}$$

**Dry Development Drilling Costs Per Year**

$$\mathrm{DDRDCST}_t = \mathrm{DNCDRY} * \frac{\mathrm{DEVDRY}}{\mathrm{DEVTIM}},\ t = \mathrm{IYRDEV}\ \text{to}\ (\mathrm{IYRDEV} + \mathrm{DEVTIM} - 1) \tag{145}$$

**Production Structure Installation Costs Per Year**

$$\mathrm{STRYCST}_t = \mathrm{STRCST} * \frac{\mathrm{NSTRUC}}{\mathrm{STRTIM}},\ t = \mathrm{IYRSTR}\ \text{to}\ (\mathrm{IYRSTR} + \mathrm{STRTIM} - 1) \tag{146}$$

**Template Installation Costs Per Year**

$$\mathrm{TMPYCST}_t = \mathrm{TEMCST} * \frac{\mathrm{NTEMP}}{\mathrm{TEMTIM}},\ t = \mathrm{IYRTEM} \tag{147}$$

**Pipeline and Gathering System Installation Costs Per Year**

$$\mathrm{PIPECST}_t = \mathrm{PIPECO},\ t = \mathrm{IYRPIP} \tag{148}$$

**Production Structure Abandonment Costs Per Year**

$$\mathrm{ABNDCST}_t = \mathrm{ABNCST},\ t = \mathrm{IYRABN} \tag{149}$$

**Intangible Capital Investments Per Year**

$$\begin{aligned}\mathrm{INTANG}_t = {} & \mathrm{EXPDCST}_t + \mathrm{DELDCST}_t + 0.7 * \mathrm{PERIT} * \mathrm{PREDCST}_t + \mathrm{PDRDCST}_t + ( \\ & \mathrm{DDRDCST}_t + 0.9 * \mathrm{PERIT} * \mathrm{STRYCST}_t + \mathrm{ABNDCST}_t + \mathrm{GNG\_EXP}_t,\ t\end{aligned} \tag{150}$$

## Tangtble Capital Investments Per Year

$$\begin{aligned} TANG_t = {} & PERT * PREDCST_t + 0.3 * PERIT * PREDCST_t + PERT * DEVDCST_t + 0. \\ & PERT * STRYCST_t + 0.1 * PERIT * STRYCST_t + PIPECST_t + GNG\_\cap_t ,\ t \end{aligned} \tag{151}$$

## Total Investments Per Year

$$INVEST_t = TANG_t + INTANG_t ,\ t = 1 \text{ to } IYRABN \tag{152}$$

## Gross Revenues Per Year

$$REV_{OIL_t} = QOIL_t * OILPRC_t ,\ t = 1 \text{ to } IYRABN \tag{153}$$

$$REV\_GAS_t = QGAS_t * GASPRC_t ,\ t = 1 \text{ to } IYRABN \tag{154}$$

$$REV\_GROS_t = REV\_OIL_t + REV\_GAS_t ,\ t = 1 \text{ to } IYRABN \tag{155}$$

## Gravity Penalties Per Year

$$GRAV\_ADJ_t = QOIL_t * GRADJ_t ,\ t = 1 \text{ to } IYRABN \tag{156}$$

## Transportation Costs Per Year

$$TRAN\_CST_t = QOIL_t * TARF\_OIL_t + QGAS_t * TARF\_GAS_t ,\ t = 1 \text{ to } IYRABN \tag{157}$$

## Adjusted Revenues Per Year

$$REV\_ADJ_t = REV\_GROS_t - GRAV\_ADJ_t - TRAN\_CST_t ,\ t = 1 \text{ to } IYRABN \tag{158}$$

## Royalty Payments Per Year

$$ROYALTY_t = REV\_ADJ_t * ROYL\_RAT ,\ t = 1 \text{ to } IYRABN \tag{159}$$

$$ROYALTY_t = 0.00 ,\ IF\ QCBOE \leq RELIEF_{WDC} \tag{160}$$

## Net Producer Revenue Per Year

$$REV\_PROD_t = REV\_ADJ_t - ROYALTY_t ,\ t = 1 \text{ to } IYRABN \tag{161}$$

**G & A on Investments and Operation Costs**

$$GNA\_CST_t = TANG_t * GNATAN + INTANG_t * GNAINT, \ t = 1 \text{ to } IYRABN \tag{162}$$

$$GNA\_OPN_t = OPCOST_t * OPOVHD, \ t = 1 \text{ to } IYRABN \tag{163}$$

**Net Revenue from Operations Per Year**

$$REV\_NET_t = REV\_PROD_t - OPCOST_t - GNA\_CST_t - GNA\_OPN_t, \ t = 1 \text{ to } IYR \tag{164}$$

**Net Income Before Taxes Per Year**

$$NET\_BTCF_t = REV\_NET_t - INTANG_t - DEPR_t - GNGRC_t, \ t = 1 \text{ to } IYRABN \tag{165}$$

**Federal Tax Bill Per Year**

$$FED\_TAXS_t = NET\_BTCF_t * FTAX\_RAT, \ t = 1 \text{ to } IYRABN \tag{166}$$

**Income Tax Credits Per Year**

$$FED\_INTC_t = INVEST_t * XINTC, \ t = 1 \text{ to } IYRABN \tag{167}$$

**Net Income After Taxes Per Year**

$$NET\_INCM_t = NET\_BTCF_t - FED\_TAXS_t + FED\_INTC_t, \ t = 1 \text{ to } IYRABN \tag{168}$$

**Annual After-Tax Cash Flow**

$$ANN\_ATCF_t = NET\_INCM_t - TANG_t + DEPR_t + GNGRC_t, \ t = 1 \text{ to } IYRABN \tag{169}$$

**Discounted After-Tax Cash Flow Per Year**

$$NPV\_ATCF_t = \frac{ANN\_ATCF_t}{DISCRT^{I}}, \ t = 1 \text{ to } IYRABN \tag{170}$$

**RESERVES DEVELOPMENT AND PRODUCTION TIMING**

**Inferred Oil Reserve Additions**

IF $POOLTYPE_{ipool}$ = 'OIL', and IF $OILPRICE_{iyr} \geq MASP\_TOT_{ipool}$

$$INFR\_OIL_{iyr} = INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}, \ iyr = \text{Current Year}, \ ipool = 1 \text{ to } NFIEI \tag{171}$$

$$INFR\_AGS_{iyr} = INFR\_AGS_{iyr} + RSRV\_GAS_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \ NFI \tag{172}$$

**Inferred Gas Reserve Additions**

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr} \geq$ MASP_TOT $_{ipool}$

$$INFR\_GAS_{iyr} = INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \ NFI \tag{173}$$

$$INFR\_CND_{iyr} = INFR\_CND_{iyr} + RSRV\_OIL_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \ NFI \tag{174}$$

**Average Supply Price for Inferred Oil Reserves**

IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr} \geq$ MASP_TOT $_{ipool}$

$$MSP\_INFO_{iyr} = \frac{MSP\_INFO_{iyr} * INFR\_OIL_{iyr} + MASP\_TOT_{ipool} * RSRV\_OIL_{ipool}}{INFR\_OIL_{iyr} + RSRV\_OIL_{ipool}}, \; iyr \tag{175}$$

**Average Supply Price for Inferred Gas Reserves**

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr} \geq$ MASP_TOT $_{ipool}$

$$MSP\_INFG_{iyr} = \frac{MSP\_INFG_{iyr} * INFR\_GAS_{iyr} + MASP\_TOT_{ipool} * RSRV\_GAS_{ipool}}{INFR\_GAS_{iyr} + RSRV\_GAS_{ipool}}, \; iy \tag{176}$$

**Wells Required for Inferred Oil Reserves**

IF POOLTYPE $_{ipool}$ = 'OIL', and IF OILPRICE$_{iyr} \geq$ MASP_TOT $_{ipool}$

$$WEL\_EXPO_{iyr} = WEL\_EXPO_{iyr} + EXPL\_WEL_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \ N \tag{177}$$

$$WEL\_DEVO_{iyr} = WEL\_DEVO_{iyr} + DEVL\_WEL_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \tag{178}$$

$$WEL\_DRYO_{iyr} = WEL\_DRYO_{iyr} + DRY\_HOLE_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \tag{179}$$

**Wells Required for Inferred Gas Reserves**

IF POOLTYPE $_{ipool}$ = 'GAS', and IF GASPRICE$_{iyr} \geq$ MASP_TOT $_{ipool}$

$$WEL\_EXPG_{iyr} = WEL\_EXPG_{iyr} + EXPL\_WEL_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \ NF \tag{180}$$

$$WEL\_DEVG_{iyr} = WEL\_DEVG_{iyr} + DEVL\_WEL_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \tag{181}$$

$$WEL\_DRYG_{iyr} = WEL\_DRYG_{iyr} + DRY\_HOLE_{ipool}, \; iyr = Current\ Year, \; ipool = 1 \ to \tag{182}$$

**Number of Structures Required for Inferred Oil Reserves**

IF POOLTYPE $_{ipool}$ = ‘OIL’, and IF $OILPRICE_{iyr} \geq MASP\_TOT_{ipool}$

$$NUM\_STRO_{iyr} = NUM\_STRO_{iyr} + STRUC\_NO_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; N \tag{183}$$

**Number of Structures Required for Inferred Gas Reserves**

IF POOLTYPE $_{ipool}$ = ‘GAS’, and IF $GASPRICE_{iyr} \geq MASP\_TOT_{ipool}$

$$NUM\_STRG_{iyr} = NUM\_STRG_{iyr} + STRUC\_NO_{ipool}, \; iyr = Current \; Year, \; ipool = 1 \; to \; N \tag{184}$$

**Relative Price Differential for Oil Reserves Vs. Gas Reserves Development**

$$RATIO1 = \frac{OILPRICE_{iyr} - MSP\_INFO_{iyr}}{OILPRICE_{iyr}}, \; iyr = Current \; Year \tag{185}$$

$$RATIO1 = \frac{GASPRICE_{iyr} - MSP\_INFG_{iyr}}{GASPRICE_{iyr}}, \; iyr = Current \; Year \tag{186}$$

$$PRP\_OIL_{iyr} = \frac{RATIO1}{RATIO1 + RATIO2}, \; iyr = Current \; Year \tag{187}$$

**Oil Well Drilling Activity**

$$WEL\_LIMT_{iyr} = WELDRLEVL * WLDRL\_RT^{iyr-1}, \; iyr = Current \; Year \tag{188}$$

$$WEL\_LIMO_{iyr} = PRP\_OIL_{iyr} * WEL\_LIMIT_{iyr}, \; iyr = Current \; Year \tag{189}$$

$$WEL\_DRLO_{iyr} = \begin{cases} WEL\_LIMO_{iyr} & \text{if } WEL\_LIMO_{iyr} \leq WEL\_DEVO_{iyr}, \; iyr = Current \; Y \\ WEL\_DEVO_{iyr} & \text{if } WEL\_LIMO_{iyr} \geq WEL\_DEVO_{iyr}, \; iyr = Current \; Y \end{cases} \tag{190}$$

**Gas Well Drilling Activity**

$$WEL\_LIMG_{iyr} = WEL\_LIMIT_{iyr} - WEL\_LIMO_{iyr}, \; iyr = Current \; Year \tag{191}$$

$$WEL\_DRLG_{iyr} = \begin{cases} WEL\_LIMG_{iyr} & \text{if } WEL\_LIMG_{iyr} \leq WEL\_DEVG_{iyr}, \; iyr = Current \; Y \\ WEL\_DEVG_{iyr} & \text{if } WEL\_LIMG_{iyr} \geq WEL\_DEVG_{iyr}, \; iyr = Current \; Y \end{cases} \tag{192}$$

**Booked Oil Reserve Additions**

$$RTIO\_OIL = \frac{WEL\_DRLO_{iyr}}{WEL\_DEVO_{iyr}}, \ iyr = Current \ \ Year \tag{193}$$

$$BKED\_OIL_{iyr} = RTIO\_OIL * INFR\_OIL_{iyr}, \ iyr = Current \ \ Year \tag{194}$$

$$BKED\_AGS_{iyr} = RTIO\_OIL * INFR\_AGS_{iyr}, \ iyr = Current \ \ Year \tag{195}$$

**Booked Gas Reserve Additions**

$$RTIO\_GAS = \frac{WEL\_DRLG_{iyr}}{WEL\_DEVG_{iyr}}, \ iyr = Current \ \ Year \tag{196}$$

$$BKED\_GAS_{iyr} = RTIO\_GAS * INFR\_GAS_{iyr}, \ iyr = Current \ \ Year \tag{197}$$

$$BKED\_CND_{iyr} = RTIO\_GAS * INFR\_CND_{iyr}, \ iyr = Current \ \ Year \tag{198}$$

**Oil Production Accounting**

***Beginning of the Year Reserves***

$$BEG\_RSVO_{iyr} = XPVD\_OIL + XPVD\_CND, \ iyr = 1 \tag{199}$$

$$BEG\_RSVO_{iyr} = END\_RSVO_{iyr-1}, \ iyr = Current \ \ Year \neq 1 \tag{200}$$

***Production in the Year***

$$PROD\_OIL_{iyr} = \frac{BEG\_RSVO_{iyr}}{RATIO\_RP} \tag{201}$$

***Reserves Growth***

$$GRO\_RSVO_{iyr} = (BEG\_RSVO_{iyr} - PROD\_OIL_{iyr}) * RES\_GROW, \ iyr = Current \ \ Year \tag{202}$$

***Reserve Additions***

$$ADD\_RSVO_{iyr} = BKED\_OIL_{iyr} + BKED\_CND_{iyr}, \ iyr = Current \ \ Year \tag{203}$$

***End of the Year Reserves***

$$END\_RSVO_{iyr} = BEG\_RSVO_{iyr} + GRO\_RSVO_{iyr} + ADD\_RSVO_{iyr} - PROD\_OIL_{iyr}, \quad (204)$$

## Gas Production Accounting

### *Beginning of the Year Reserves*

$$BEG\_RSVG_{iyr} = XPVD\_GAS + XPVD\_AGS, \ iyr = 1 \quad (205)$$

$$BEG\_RSVG_{iyr} = END\_RSVG_{iyr}, \ iyr = Current \ Year \neq 1 \quad (206)$$

### *Production in the Year*

$$PROD\_GAS_{iyr} = \frac{BEG\_RSVG_{iyr}}{RATIO\_RP}, \ iyr = Current \ Year \quad (207)$$

### *Reserves Growth*

$$GRO\_RSVG_{iyr} = (BEG\_RSVG_{iyr} - PROD\_GAS_{iyr}) * RES\_GROW, \ iyr = Current \ Year \quad (208)$$

### *Reserve Additions*

$$ADD\_RSVG_{iyr} = BKED\_GAS_{iyr} + BKED\_AGS_{iyr}, \ iyr = Current \ Year \quad (209)$$

### *End of the Year Reserves*

$$END\_RSVG_{iyr} = BEG\_RSVG_{iyr} + GRO\_RSVG_{iyr} + ADD\_RSVG_{iyr} - PROD\_GAS_{iyr}, \quad (210)$$

## Advanced Technology Impacts on Exploration

$$MASP\_EXP_{ipool,new} = \frac{MASP\_EXP_{ipool,old}}{ADT\_EXPL}, \ ipool = 1 \ to \ NFIELD \quad (211)$$

$$MASP\_TOT = MASP\_TOT - (MASP\_EXP_{ipool,old} - MASP\_EXP_{ipool,new}), \ ipool = 1 \ to \quad (212)$$

## Advanced Technology Impacts on Drilling

$$MASP\_DRL_{ipool,new} = \frac{MASP\_DRL_{ipool,old}}{ADT\_DRLG}, \ ipool = 1 \ to \ NFIELD \quad (213)$$

$$MASP\_TOT = MASP\_TOT - (MASP\_DRL_{ipool,old} - MASP\_DRL_{ipool,new}), \ ipool = 1 \ tc \quad (214)$$

## Advanced Technology Impacts on Structure

$$MASP\_STR_{ipool,new} = \frac{MASP\_STR_{ipool,old}}{ADT\_STRC}, \; ipool = 1 \; to \; NFIELD \tag{215}$$

$$MASP\_TOT = MASP\_TOT - (MASP\_STR_{ipool,old} - MASP\_STR_{ipool,new}), \; ipool = 1 \; to \tag{216}$$

## Advanced Technology Impacts on Operations

$$MASP\_OPR_{ipool,new} = \frac{MASP\_OPR_{ipool,old}}{ADT\_OPER}, \; ipool = 1 \; to \; NFIELD \tag{217}$$

$$MASP\_TOT = MASP\_TOT - (MASP\_OPR_{ipool,old} - MASP\_OPR_{ipool,new}), \; ipool = 1 \; to \tag{218}$$

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# Appendix D. 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 Analysis Branch 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
   1998

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: Energy Supply and Conversion
   - Branch: Oil and Gas Analysis
   - Model Contact: Ted McCallister
   - Telephone: (202) 586-4820

9. Documentation Reference
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10. Archive Media and Installation Manual
    NEMS98

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 and Mexico, as well as liquefied natural gas (LNG) trade. U.S. natural gas trade with Canada is represented by six entry/exit points and trade with Mexico by three entry/exit points. Four LNG receiving terminals are represented.

12. Coverage
    - Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    - Time Units/Frequency: Annually 1990 through 2020
    - 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 five major components
        - Lower 48 Onshore and Shallow Offshore Supply Submodule
        - Deep Water Offshore Supply Submodule
        - Foreign Natural Gas Supply Submodule
        - Enhanced Oil Recovery Submodule
        - Alaska Oil and Gas Supply Submodule
    - Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States and Canada 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

- 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 - American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-1995)*, Washington, D.C.

- Shallow Offshore Drilling Costs - American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-1995)*, 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)

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15. DOE Input Data

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- 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

- Undiscovered Recoverable Resource Base - Energy Information Administration. *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy strategy*, SR/NES/92-05

- Oil and Gas Reserves - Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-1996), DOE/EIA-0216(77-96)

16. Computing Environment
    - Hardware Used: RS/6000
    - Operating System: UNIX
    - 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 Reviews, Model Quality Audit

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix C of this document.

# Appendix E.  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 Canadian oil and gas wells equations. Finally, the appendix documents the estimation of oil and gas supply price elasticities that are passed to the PMM and the NGTDM for (possible) use in their short run supply functions. The econometric software packages, SAS and TSP, were used for the estimations.

# Lower 48 Estimated Wells Equations

## Onshore

$$LESTWELLS_t = b0 + b1 * (LPOIL_t * LPGAS_t) + \rho * LESTWELLS_{t-1} - \rho * (b0 + b1 * (LPOIL_{t-1} * LPGAS_{t-1})) \qquad (1)$$

| Equation Variable/Parameter | Output Variable/Parameter |
|---|---|
| LESTWELLS | LNWELLS |
| b0 | C |
| b1 | POILGAS |
| ρ | rho |

CONVERGENCE ACHIEVED AFTER 10 ITERATIONS
Dependent variable: LNWELLS
Current sample: 16 to 26
Number of observations: 11

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 4.24825 | Mean of dependent variable = 10.2911 |
| Std. dev. of dependent var. = 1.49820 | Std. dev. of dependent var. = .366724 |
| Sum of squared residuals = .094444 | Sum of squared residuals = .095338 |
| Variance of residuals = .010494 | Variance of residuals = .010593 |
| Std. error of regression = .102439 | Std. error of regression = .102923 |
| R-squared = .995858 | R-squared = .934892 |
| Adjusted R-squared = .995398 | Adjusted R-squared = .927658 |
| Durbin-Watson statistic = 1.62497 | Durbin-Watson statistic = 1.60611 |
| Rho (autocorrelation coef.) = .619618 | |
| Standard error of rho = .242090 | |
| t-statistic for rho = 2.55946 | |
| F-statistic (zero slopes) = 2129.97 | |
| Log of likelihood function = 10.3165 | |

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| C | 9.69488 | .108701 | 89.1886 |
| POILGAS | .445058 | .057264 | 7.77197 |

## Offshore

$$LGOMWELLS_t = \alpha + \beta * (LPOIL_t * LPGAS_t) + \rho * LGOMWELLS_{t-1} - \rho * (\alpha + \beta * (LPOIL * LPGAS)) \qquad (2)$$

| Equation Variable/Parameter | Output Variable/Parameter |
|---|---|
| LGOMWELLS | LN of offshore wells |
| α | C |
| β | POILGAS |
| ρ | rho |

OFFSHORE WELLS Equation;

Method = MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

Dependent variable: LN of offshore wells
Current sample: 1976 to 1995
Number of observations: 20

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 3.84150 | Mean of dependent variable = 6.86104 |
| Std. dev. of dependent var. = .563992 | Std. dev. of dependent var. = .249356 |
| Sum of squared residuals = .587669 | Sum of squared residuals = .599544 |
| Variance of residuals = .032648 | Variance of residuals = .033308 |
| Std. error of regression = .180688 | Std. error of regression = .182505 |
| R-squared = .913079 | R-squared = .494779 |
| Adjusted R-squared = .908250 | Adjusted R-squared = .466711 |
| Durbin-Watson statistic = 2.05045 | Durbin-Watson statistic = 2.00796 |
| Rho (autocorrelation coef.) = .457058 | |
| Standard error of rho = .208361 | |
| t-statistic for rho = 2.19359 | |
| F-statistic (zero slopes) = 167.114 | |
| Log of likelihood function = 6.77730 | |

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| C | 6.64343 | .113502 | 58.5316 |
| POILGAS | .113775 | .047312 | 2.40477 |

POILGAS is the natural log of the GOM oil price in 87$ multiplied by the natural log of the GOM natural gas price in 87$

# Lower 48 RIGS Equations

## Onshore

$$LRIGSL48_t = b0 + b1 * LRIGSL48_{t-1} + b2 * LREVRIG_{t-1} + \rho * LRIGSL48_{t-2} - \rho * (b0 + b1 * LRIGSL48_{t-2} + b2 * LREVRIG_{t-3}) \tag{3}$$

| Equation Variable/Parameter | Output Variable/Parameter |
|---|---|
| LRIGSL48 | LNRIGS |
| b0 | ALPHA |
| b1 | RIG |
| b2 | REV |
| ρ | RHO_RIG |

```
LOWER 48 ONSHORE RIGS
MODEL Procedure
2SLS Estimation

Nonlinear 2SLS Summary of Residual Errors

             DF    DF                                                      Durbin
Equation  Model Error        SSE         MSE     Root MSE  R-Square  Adj R-Sq  Watson

LNRIGS        4    20    0.05812   0.0029061      0.05391    0.9833    0.9808   1.656


Nonlinear 2SLS Parameter Estimates

                          Approx.        'T'   Approx.  1st Stage
Parameter    Estimate     Std Err      Ratio  Prob>|T|   R-Square

ALPHA       -3.307321     0.76235      -4.34    0.0003     1.0000
RIG          0.800700     0.05402      14.82    0.0001     1.0000
REV          0.316745     0.05242       6.04    0.0001     1.0000
RHO_RIG      0.446480     0.22715       1.97    0.0634     1.0000


Number of Observations       Statistics for System
Used                 24      Objective    0.0000356
Missing               0      Objective*N  0.000854
```

## Offshore

$$LRIGSOFF_t = \alpha + \beta * LRIGSOFF_{t-1} + \gamma * LREVRIG_{t-2} \qquad (4)$$

| Equation Variable/Parameter | Output Variable/Parameter |
|---|---|
| LRIGSOFF | LNRIGS |
| α | C |
| β | LNRIGS(-1) |
| γ | REV_RIG(-2) |

Offshore rigs equation

```
                    Equation   1
                    ============

            Method of estimation = Ordinary Least Squares


Dependent variable: LNRIGS
Current sample:  3 to 26
Number of observations:  24

 Mean of dependent variable = 5.37463        Durbin-Watson statistic = 1.84314
Std. dev. of dependent var. = .374642                  Durbin's h = .312670
  Sum of squared residuals = .363109        Durbin's h alternative = .326519
     Variance of residuals = .017291     F-statistic (zero slopes) = 82.8495
  Std. error of regression = .131495    Schwarz Bayes. Info. Crit. = -3.79385
                 R-squared = .887520     Log of likelihood function = 16.2387
        Adjusted R-squared = .876807

           Estimated    Standard
Variable     Coefficient     Error       t-statistic
C           -4.19920      1.80272       -2.32936
LNRIGS(-1)   .833120       .076091       10.9490
REV_RIG(-2)  .311413       .115816       2.68887

*************************
```

## Drilling Cost Equations

Drilling costs were hypothesized to be a function of drilling, depth, and a time trend that proxies for the cumulative effect of technological advances on costs. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique available in SAS. The forms of the equations are:

### Onshore Regions

$$\begin{aligned} LDRILLCOST_{r,k,t} = {} & \ln(\delta 0)_{r,k} + \ln(\delta 1)_{d,k} + \ln(\delta 2)_{r,k} + \delta 3_k * LESTWELLS_t + \delta 4_k * LRIGSL48_t + \delta 5_k * TIME_t + \\ & \rho_k * LDRILLCOST_{r,k,t-1} - \rho_k * \left(\ln(\delta 0)_{r,k}\right) + \ln(\delta 1)_{d,k} + \ln(\delta 2)_{r,k} + \\ & \delta 3_k * LESTWELLS_{t-1} + \delta 4_k * LRIGSL48_{t-1} + \delta 5_k * TIME_{t-1}\big) \end{aligned} \tag{5}$$

**Results**

Mapping of variable names from the above equation to the following SAS output

| Variable/Parameter | Successful | | Dry | |
|---|---|---|---|---|
| | Oil | Gas | Oil | Gas |
| LDRILLCOST | LNOILCOST | LNGASCOST | LNDOL_C | LNDGAS_C |
| $\ln(\delta 0)_1$ | REGOIL1 | REGGAS1 | REGDOIL1 | REGDGAS1 |
| $\ln(\delta 0)_2$ | REGOIL2 | REGGAS2 | REGDOIL2 | REGDGAS2 |
| $\ln(\delta 0)_3$ | REGOIL3 | REGGAS3 | REGDOIL3 | REGDGAS3 |
| $\ln(\delta 0)_4$ | REGOIL4 | REGGAS4 | REGDOIL4 | REGDGAS4 |
| $\ln(\delta 0)_5$ | REGOIL5 | REGGAS5 | REGDOIL5 | REGDGAS5 |
| $\ln(\delta 0)_6$ | REGOIL6 | REGGAS6 | REGDOIL6 | REGDGAS6 |
| $\ln(\delta 1)_{r,2500}$ | OIL_2500 | GAS_2500 | DOIL_2500 | DGAS_2500 |
| $\ln(\delta 1)_{r,3750}$ | OIL_3750 | GAS_3750 | DOIL_3750 | DGAS_3750 |
| $\ln(\delta 1)_{r,5000}$ | OIL_5000 | GAS_5000 | DOIL_5000 | DGAS_5000 |
| $\ln(\delta 1)_{r,7500}$ | OIL_7500 | GAS_7500 | DOIL_7500 | DGAS_7500 |
| $\ln(\delta 1)_{r,10000}$ | O_10000 | G_10000 | DO_10000 | DG_10000 |
| $\ln(\delta 1)_{r,12500}$ | O_12500 | G_12500 | DO_12500 | DG_12500 |
| $\ln(\delta 2)_{1,5000}$ | OGD16_50 | OGD16_50 | OGD16_50 | OGD16_50 |

| | | | | |
|---|---|---|---|---|
| $\ln(\delta 2)_{6,5000}$ | OGD16_50 | OGD16_50 | OGD16_50 | OGD16_50 |
| $\delta 3$ | OG_WELL | OG_WELL | DWELL | DWELL |
| $\delta 4$ | OGD_RIGS | OGD_RIGS | OGD_RIGS | OGD_RIGS |
| $\delta 5$ | TECH | TECH | TECH | TECH |
| $\rho$ | RHO_O | RHO_G | RHO_DO | RHO_DG |

MODEL Procedure
3SLS Estimation

Nonlinear 3SLS Summary of Residual Errors

| Equation | DF Model | DF Error | SSE | MSE | Root MSE | R-Square | Adj R-Sq | Durbin Watson |
|---|---|---|---|---|---|---|---|---|
| LNOILCST | 14.25 | 698.8 | 13.86919 | 0.01985 | 0.14088 | 0.9844 | 0.9841 | 2.055 |
| LNGASCST | 14.25 | 698.8 | 23.53795 | 0.03369 | 0.18354 | 0.9754 | 0.9750 | 1.945 |
| LNDOIL_C | 14.25 | 698.8 | 31.13241 | 0.04455 | 0.21108 | 0.9711 | 0.9705 | 1.959 |
| LNDGAS_C | 14.25 | 698.8 | 32.26854 | 0.04618 | 0.21490 | 0.9718 | 0.9713 | 2.001 |

Nonlinear 3SLS Parameter Estimates

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>\|T\| | 1st Stage R-Square |
|---|---|---|---|---|---|
| REGOIL1 | 33.034536 | 4.76927 | 6.93 | 0.0001 | 1.0000 |
| REGOIL2 | 33.633224 | 4.76853 | 7.05 | 0.0001 | 1.0000 |
| REGOIL3 | 33.502738 | 4.76885 | 7.03 | 0.0001 | 1.0000 |
| REGOIL4 | 33.489193 | 4.76876 | 7.02 | 0.0001 | 1.0000 |
| REGOIL5 | 33.771738 | 4.76854 | 7.08 | 0.0001 | 1.0000 |
| REGOIL6 | 34.246812 | 4.77110 | 7.18 | 0.0001 | 1.0000 |
| OGD_RIGS | -0.116294 | 0.05453 | -2.13 | 0.0333 | 0.9998 |
| OG_WELL | 0.422219 | 0.04508 | 9.37 | 0.0001 | 0.9998 |
| TECH | -0.013218 | 0.0023225 | -5.69 | 0.0001 | 1.0000 |
| OGD16_50 | 0.230538 | 0.10062 | 2.29 | 0.0223 | 1.0000 |
| OIL_2500 | 0.975192 | 0.04985 | 19.56 | 0.0001 | 1.0000 |
| OIL_3750 | 1.341276 | 0.05010 | 26.77 | 0.0001 | 1.0000 |
| OIL_5000 | 1.789970 | 0.04986 | 35.90 | 0.0001 | 1.0000 |
| OIL_7500 | 2.314714 | 0.05010 | 46.20 | 0.0001 | 1.0000 |
| O_10000 | 2.835915 | 0.05010 | 56.60 | 0.0001 | 1.0000 |
| O_12500 | 3.438827 | 0.05011 | 68.63 | 0.0001 | 1.0000 |
| RHO_O | 0.590745 | 0.01730 | 34.14 | 0.0001 | 0.9804 |
| REGGAS1 | 33.477054 | 4.77006 | 7.02 | 0.0001 | 0.0128 |
| REGGAS2 | 33.952346 | 4.76948 | 7.12 | 0.0001 | 1.0000 |
| REGGAS3 | 33.806066 | 4.76925 | 7.09 | 0.0001 | 1.0000 |
| REGGAS4 | 33.761813 | 4.76932 | 7.08 | 0.0001 | 1.0000 |
| REGGAS5 | 34.006795 | 4.76923 | 7.13 | 0.0001 | 1.0000 |
| REGGAS6 | 34.158216 | 4.77227 | 7.16 | 0.0001 | 1.0000 |
| GAS_2500 | 0.817494 | 0.06563 | 12.46 | 0.0001 | 1.0000 |
| GAS_3750 | 1.080081 | 0.06654 | 16.23 | 0.0001 | 1.0000 |
| GAS_5000 | 1.480476 | 0.06563 | 22.56 | 0.0001 | 1.0000 |
| GAS_7500 | 2.052473 | 0.06654 | 30.85 | 0.0001 | 1.0000 |
| G_10000 | 2.739287 | 0.06654 | 41.17 | 0.0001 | 1.0000 |
| G_12500 | 3.594194 | 0.06665 | 53.92 | 0.0001 | 1.0000 |
| RHO_G | 0.596323 | 0.01658 | 35.97 | 0.0001 | 0.9875 |
| REGDOIL1 | 32.524648 | 4.78119 | 6.80 | 0.0001 | -0.0525 |
| REGDOIL2 | 32.792248 | 4.78061 | 6.86 | 0.0001 | 1.0000 |
| REGDOIL3 | 32.657575 | 4.78089 | 6.83 | 0.0001 | 1.0000 |
| REGDOIL4 | 32.640585 | 4.78062 | 6.83 | 0.0001 | 1.0000 |
| REGDOIL5 | 32.962689 | 4.78051 | 6.90 | 0.0001 | 1.0000 |
| REGDOIL6 | 33.361578 | 4.78435 | 6.97 | 0.0001 | 1.0000 |
| DWELL | 0.467314 | 0.04973 | 9.40 | 0.0001 | 0.9998 |
| DOIL2500 | 0.680103 | 0.07143 | 9.52 | 0.0001 | 1.0000 |
| DOIL3750 | 1.122136 | 0.07256 | 15.47 | 0.0001 | 1.0000 |
| DOIL5000 | 1.680855 | 0.07143 | 23.53 | 0.0001 | 1.0000 |
| DOIL7500 | 2.307416 | 0.07256 | 31.80 | 0.0001 | 1.0000 |
| DO_10000 | 2.841329 | 0.07256 | 39.16 | 0.0001 | 1.0000 |
| DO_12500 | 3.678567 | 0.07256 | 50.70 | 0.0001 | 1.0000 |
| RHO_DO | 0.580446 | 0.01679 | 34.56 | 0.0001 | 0.9879 |
| REGDGAS1 | 32.967689 | 4.78166 | 6.89 | 0.0001 | -0.1045 |
| REGDGAS2 | 33.108615 | 4.78136 | 6.92 | 0.0001 | 1.0000 |
| REGDGAS3 | 32.957202 | 4.78113 | 6.89 | 0.0001 | 1.0000 |
| REGDGAS4 | 32.914844 | 4.78105 | 6.88 | 0.0001 | 1.0000 |
| REGDGAS5 | 33.193303 | 4.78099 | 6.94 | 0.0001 | 1.0000 |
| REGDGAS6 | 33.299708 | 4.78514 | 6.96 | 0.0001 | 1.0000 |
| DGAS2500 | 0.522544 | 0.07382 | 7.08 | 0.0001 | 1.0000 |
| DGAS3750 | 0.864050 | 0.07503 | 11.52 | 0.0001 | 1.0000 |
| DGAS5000 | 1.373319 | 0.07382 | 18.60 | 0.0001 | 1.0000 |
| DGAS7500 | 2.044347 | 0.07503 | 27.25 | 0.0001 | 1.0000 |
| DG_10000 | 2.753664 | 0.07503 | 36.70 | 0.0001 | 1.0000 |
| DG_12500 | 3.835120 | 0.07506 | 51.09 | 0.0001 | 1.0000 |
| RHO_DG | 0.582286 | 0.01732 | 33.62 | 0.0001 | 0.9865 |

| Number of Observations | | Statistics for System | |
|---|---|---|---|
| Used | 713 | Objective | 0.3600 |
| Missing | 0 | Objective*N | 256.6453 |

## Offshore Gulf of Mexico

$$LDRILLCOST_k = \ln(\delta 0)_k + \delta 1_k * GOMWELLS_t + \ln(\delta 2)_{d,k} + \delta 3_k * LRIGSOFF_{t-2} + \delta 4_k * TIME_t \quad (6)$$

**Results**

Mapping of variable names from the above equation to the following SAS output

| Variable/Parameter | Successful | | Dry | |
|---|---|---|---|---|
| | Oil | Gas | Oil | Gas |
| LDRILLCOST | LNOILCST | LNGASCST | LNDOIL_C | LNDGAS_C |
| $\ln(\delta 0)$ | OIL_C | GAS_C | DOIL_C | DGAS_C |
| $\delta 1$ | OG_WELL | OG_WELL | DWELL | DWELL |
| $\ln(\delta 2)_{5000}$ | OIL_5000 | GAS_5000 | DOIL5000 | DGAS5000 |
| $\ln(\delta 2)_{7500}$ | OIL_7500 | GAS_7500 | DOIL7500 | DGAS7500 |
| $\ln(\delta 2)_{10000}$ | O_10000 | G_10000 | DO_10000 | DG_10000 |
| $\ln(\delta 2)_{12500}$ | O_12500 | G_12500 | DO_12500 | DG_12500 |
| $\ln(\delta 2)_{15000}$ | O_15000 | G_15000 | DO_15000 | DG_15000 |
| $\delta 3$ | OGD_RIGS | OGD_RIGS | OGD_RIGS | OGD_RIGS |
| $\delta 4$ | TECH | TECH | TECH | TECH |

Offshore Drilling Cost Equations
Method of estimation = THREE STAGE LEAST SQUARES
========================

EQUATIONS: OIL GAS DOIL DGAS

INSTRUMENTS: YEAR REV_RIG(-2) LNRIGS(-2) LNWELLS(-1) LNPOIL LNPGAS LNPOIL(-1) LNPGAS(-1) D_5000 D_7500 D_10000 D_12500 D_15000

| Parameter | Estimate | Standard Error | t-statistic |
|---|---|---|---|
| OIL_C | 57.1710 | 12.4289 | 4.59985 |
| OGD_RIGS | -.156919 | .081737 | -1.91981 |
| OG_WELL | .660277 | .117293 | 5.62931 |
| TECH | -.023452 | .591602E-02 | -3.96424 |
| OIL_5000 | .142007 | .077730 | 1.82694 |
| OIL_7500 | .498102 | .077730 | 6.40813 |
| O_10000 | .799924 | .077730 | 10.2911 |
| O_12500 | 1.09091 | .077730 | 14.0347 |
| O_15000 | 1.52866 | .077730 | 19.6664 |
| GAS_C | 57.2468 | 12.4289 | 4.60596 |
| GAS_5000 | .215527 | .069397 | 3.10569 |
| GAS_7500 | .516113 | .069397 | 7.43707 |
| G_10000 | .770359 | .069397 | 11.1007 |
| G_12500 | 1.13132 | .069397 | 16.3021 |
| G_15000 | 1.59024 | .069397 | 22.9149 |
| DOIL_C | 55.9475 | 12.4272 | 4.50203 |
| DWELL | .794773 | .113375 | 7.01010 |
| DOIL5000 | .205922 | .076049 | 2.70775 |
| DOIL7500 | .588334 | .076049 | 7.73622 |
| DO_10000 | .975994 | .076049 | 12.8337 |
| DO_12500 | 1.32699 | .076049 | 17.4491 |
| DO_15000 | 1.83982 | .076049 | 24.1925 |
| DGAS_C | 56.0393 | 12.4271 | 4.50943 |
| DGAS5000 | .272374 | .063244 | 4.30671 |
| DGAS7500 | .585668 | .063244 | 9.26043 |
| DG_10000 | .928625 | .063244 | 14.6832 |
| DG_12500 | 1.34876 | .063244 | 21.3263 |
| DG_15000 | 1.88679 | .063244 | 29.8335 |

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Equation OIL
===============

Dependent variable: LNOILCST

| | |
|---|---|
| Mean of dependent variable = 14.8956 | Std. error of regression = .227759 |
| Std. dev. of dependent var. = .608018 | R-squared = .859209 |
| Sum of squared residuals = 5.29119 | Durbin-Watson statistic = 1.83336 |
| Variance of residuals = .051874 | |

Equation GAS
===============

Dependent variable: LNGASCST

| | |
|---|---|
| Mean of dependent variable = 14.9987 | Std. error of regression = .203527 |
| Std. dev. of dependent var. = .610118 | R-squared = .888201 |
| Sum of squared residuals = 4.22517 | Durbin-Watson statistic = 1.96565 |
| Variance of residuals = .041423 | |

Equation DOIL
================

Dependent variable: LNDOIL_C

| | |
|---|---|
| Mean of dependent variable = 14.7383 | Std. error of regression = .221501 |
| Std. dev. of dependent var. = .720214 | R-squared = .904578 |
| Sum of squared residuals = 5.00438 | Durbin-Watson statistic = 1.79762 |
| Variance of residuals = .049063 | |

Equation DGAS
================

Dependent variable: LNDGAS_C

| | |
|---|---|
| Mean of dependent variable = 14.8443 | Std. error of regression = .184143 |
| Std. dev. of dependent var. = .713234 | R-squared = .932781 |
| Sum of squared residuals = 3.45866 | Durbin-Watson statistic = 2.15817 |
| Variance of residuals = .033908 | |

# Onshore Lease Equipment Cost Equations

Lease equipment costs were hypothesized to be a function of total successful wells and a time trend that proxies for the cumulative effect of technological advances on costs. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique available in SAS. Where necessary, equations were estimated in generalized difference form to correct for first order serial correlation. The forms of the equations are:

## Onshore Regions

$$\begin{aligned} LLEQC_{r,k,t} = {} & \ln(\epsilon 0)_{r,k} + \ln(\epsilon 1)_k * DEPTH_{r,k,t} + \epsilon 2_k * LESUCWELL_{k,t} + \epsilon 3_k * TIM \\ & \rho_k * (\ln(\epsilon 0)_{r,k} + \ln(\epsilon 1)_k * DEPTH_{r,k,t-1} * \epsilon 2_k * LESUCWELL_{k,t-1} + \end{aligned} \qquad (7)$$

**Results**

Mapping of variable names from the above equation to the following SAS output

| Variable/Parameter | Oil | Gas | Deep Gas |
|---|---|---|---|
| LLEQC | LOILC | LSGASC | LDGASC |
| $\ln(\epsilon 0)_1$ | OILREG1 | SGSREG1 | -- |
| $\ln(\epsilon 0)_2$ | OILREG2 | SGSREG2 | DGSREG2 |
| $\ln(\epsilon 0)_3$ | OILREG3 | SGSREG3 | DGSREG3 |
| $\ln(\epsilon 0)_4$ | OILREG4 | SGSREG4 | DGSREG4 |
| $\ln(\epsilon 0)_5$ | OILREG5 | SGSREG5 | DGSREG5 |
| $\ln(\epsilon 0)_6$ | OILREG6 | SGSREG6 | -- |
| $\epsilon 1$ | ODEP | SGDEP | DGDEP |
| $\epsilon 2$ | OWELL | SGSWELL | DGSWELL |
| $\epsilon 3$ | TECH | TECH | TECH |
| $\rho$ | OILRHO | SGSRHO | DGSRHO |

MODEL Procedure
3SLS Estimation

Nonlinear 3SLS Summary of Residual Errors

| Equation | DF Model | DF Error | SSE | MSE | Root MSE | R-Square | Adj R-Sq | Durbin Watson |
|---|---|---|---|---|---|---|---|---|
| LOILC | 10 | 128 | 0.51288 | 0.0040069 | 0.06330 | 0.9537 | 0.9504 | 2.207 |
| LSGASC | 10 | 128 | 0.30846 | 0.0024098 | 0.04909 | 0.9872 | 0.9863 | 1.378 |

Nonlinear 3SLS Parameter Estimates

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>\|T\| | 1st Stage R-Square |
|---|---|---|---|---|---|
| OILREG1 | 34.240053 | 5.56138 | 6.16 | 0.0001 | 1.0000 |
| OILREG2 | 33.997809 | 5.56458 | 6.11 | 0.0001 | 1.0000 |
| OILREG3 | 34.233863 | 5.56393 | 6.15 | 0.0001 | 1.0000 |
| OILREG4 | 34.338364 | 5.56310 | 6.17 | 0.0001 | 1.0000 |
| OILREG5 | 34.334478 | 5.56042 | 6.17 | 0.0001 | 1.0000 |
| OILREG6 | 34.550843 | 5.56102 | 6.21 | 0.0001 | 1.0000 |
| ODEP | 0.00011844 | 7.41963E-6 | 15.96 | 0.0001 | 1.0000 |
| OILWELL | 0.149728 | 0.02879 | 5.20 | 0.0001 | 1.0000 |
| TECH | -0.012578 | 0.0027217 | -4.62 | 0.0001 | 1.0000 |
| OILRHO | 0.554821 | 0.07439 | 7.46 | 0.0001 | 1.0000 |
| SGSREG1 | 33.539031 | 5.52249 | 6.07 | 0.0001 | 1.0000 |
| SGSREG2 | 33.526017 | 5.52187 | 6.07 | 0.0001 | 1.0000 |
| SGSREG3 | 33.819412 | 5.52410 | 6.12 | 0.0001 | 1.0000 |
| SGSREG4 | 34.333544 | 5.52300 | 6.22 | 0.0001 | 1.0000 |
| SGSREG5 | 34.469401 | 5.51910 | 6.25 | 0.0001 | 1.0000 |
| SGSREG6 | 33.557449 | 5.52380 | 6.08 | 0.0001 | 1.0000 |
| SGDEP | 0.000047576 | 0.00001719 | 2.77 | 0.0065 | 1.0000 |
| SGSWELL | 0.103441 | 0.02371 | 4.36 | 0.0001 | 1.0000 |
| SGSRHO | 0.727288 | 0.04286 | 16.97 | 0.0001 | 1.0000 |
| YR84 | 0.060748 | 0.02030 | 2.99 | 0.0033 | 1.0000 |

| Number of Observations | | Statistics for System | |
|---|---|---|---|
| Used | 138 | Objective | 0.5306 |
| Missing | 0 | Objective*N | 73.2277 |

# Onshore Operating Cost Equations

Operating costs were hypothesized to be a function of drilling, depth, and a time trend that proxies for the cumulative effect of technological advances on costs. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using Three Stage Least Squares (3SLS) technique available in SAS. The forms of the equations are:

## Onshore Regions

$$\begin{aligned} LOPC_{r,k,t} = {} & \ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t} + \varphi 2_k * LESUCWELL_{k,t} + \varphi 3_k * TIM \\ & \rho_k * (\ln(\varphi 0)_{r,k} + \ln(\varphi 1)_k * DEPTH_{r,k,t-1} * \varphi 2_k * LESUCWELL_{k,t-1} + \varphi \end{aligned} \tag{8}$$

**Results**

Mapping of variable names from the above equation to the following SAS output

| Variable/Parameter | Oil | Gas | Deep Gas |
|---|---|---|---|
| LOPC | LOILC | LSGASC | LDGASC |
| $\ln(\phi 0)_1$ | OILREG1 | SGSREG1 | -- |
| $\ln(\phi 0)_2$ | OILREG2 | SGSREG2 | DGSREG2 |
| $\ln(\phi 0)_3$ | OILREG3 | SGSREG3 | DGSREG3 |
| $\ln(\phi 0)_4$ | OILREG4 | SGSREG4 | DGSREG4 |
| $\ln(\phi 0)_5$ | OILREG5 | SGSREG5 | DGSREG5 |
| $\ln(\phi 0)_6$ | OILREG6 | SGSREG6 | -- |
| $\phi 1$ | ODEP | SGDEP | DGDEP |
| $\phi 2$ | OILWELL | SGSWELL | DGSWELL |
| $\phi 3$ | TECH | TECH | TECH |
| $\rho$ | ORHO | SGSRHO | DGSRHO |

MODEL Procedure
3SLS Estimation

Nonlinear 3SLS Summary of Residual Errors

| Equation | DF Model | DF Error | SSE | MSE | Root MSE | R-Square | Adj R-Sq | Durbin Watson |
|---|---|---|---|---|---|---|---|---|
| LOILC | 9.5 | 128.5 | 0.75038 | 0.0058396 | 0.07642 | 0.9387 | 0.9347 | 2.024 |
| LSGASC | 9.5 | 128.5 | 0.20196 | 0.0015717 | 0.03964 | 0.9817 | 0.9804 | 2.103 |

Nonlinear 3SLS Parameter Estimates

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>\|T\| | 1st Stage R-Square |
|---|---|---|---|---|---|
| OILREG1 | 23.970499 | 8.67819 | 2.76 | 0.0066 | 1.0000 |
| OILREG2 | 23.917828 | 8.68086 | 2.76 | 0.0067 | 1.0000 |
| OILREG3 | 23.757314 | 8.67942 | 2.74 | 0.0071 | 1.0000 |
| OILREG4 | 23.673082 | 8.67693 | 2.73 | 0.0073 | 1.0000 |
| OILREG5 | 24.117749 | 8.65696 | 2.79 | 0.0061 | 1.0000 |
| OILREG6 | 24.206967 | 8.68353 | 2.79 | 0.0061 | 1.0000 |
| ODEP | 0.00010205 | 8.14579E-6 | 12.53 | 0.0001 | 1.0000 |
| OILWELL | 0.124215 | 0.03629 | 3.42 | 0.0008 | 1.0000 |
| TECH | -0.00809288 | 0.0042922 | -1.89 | 0.0616 | 1.0000 |
| OILRHO | 0.841124 | 0.04620 | 18.20 | 0.0001 | 1.0000 |
| SGSREG1 | 24.155929 | 8.71401 | 2.77 | 0.0064 | 1.0000 |
| SGSREG2 | 24.539760 | 8.71327 | 2.82 | 0.0056 | 1.0000 |
| SGSREG3 | 24.509981 | 8.71548 | 2.81 | 0.0057 | 1.0000 |
| SGSREG4 | 24.775591 | 8.71161 | 2.84 | 0.0052 | 1.0000 |
| SGSREG5 | 24.854523 | 8.70793 | 2.85 | 0.0050 | 1.0000 |
| SGSREG6 | 24.154175 | 8.71220 | 2.77 | 0.0064 | 1.0000 |
| SGDEP | 0.000059598 | 0.00001395 | 4.27 | 0.0001 | 1.0000 |
| GASWELL | 0.080007 | 0.02407 | 3.32 | 0.0012 | 1.0000 |
| SGSRHO | 0.785011 | 0.05725 | 13.71 | 0.0001 | 1.0000 |

| Number of Observations | | Statistics for System | |
|---|---|---|---|
| Used | 138 | Objective | 0.6044 |
| Missing | 0 | Objective*N | 83.4107 |

# Onshore Well Equations

## Onshore Region 1

### *Exploration - Oil*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DCFON_{i,r,k,t-2} + m3_{i,r,k}*DUM86_{t} \quad (35)$$

for i=1, r=1, k=1

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 9 to 26
Number of observations: 18

| | |
|---|---|
| Mean of dependent variable = 831.278 | Adjusted R-squared = .909008 |
| Std. dev. of dependent var. = 710.023 | Durbin-Watson statistic = 1.68775 |
| Sum of squared residuals = 642208. | F-statistic (zero slopes) = 57.6099 |
| Variance of residuals = 45872.0 | Schwarz Bayes. Info. Crit. = 11.1246 |
| Std. error of regression = 214.177 | Log of likelihood function = -119.882 |
| R-squared = .925065 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 1226.36 | 87.8807 | 13.9549 |
| m1 | .848130E-03 | .325041E-03 | 2.60930 |
| m2 | .143626E-02 | .283427E-03 | 5.06747 |
| m3 | -747.665 | 127.899 | -5.84575 |

### *Exploration - Shallow Gas*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM81_{t} + m3_{i,r,k}*DUM86_{t} \text{ for } i=1, r=1, k=2 \quad (36)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

| | |
|---|---|
| Mean of dependent variable = 898.350 | Adjusted R-squared = .920400 |
| Std. dev. of dependent var. = 525.507 | Durbin-Watson statistic = 1.55206 |
| Sum of squared residuals = 351713. | F-statistic (zero slopes) = 74.2315 |
| Variance of residuals = 21982.1 | Schwarz Bayes. Info. Crit. = 10.3740 |
| Std. error of regression = 148.264 | Log of likelihood function = -126.127 |
| R-squared = .932969 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 857.190 | 112.500 | 7.61944 |
| m1 | .174409E-03 | .660434E-04 | 2.64083 |
| m2 | 378.432 | 105.760 | 3.57821 |
| m3 | -960.898 | 110.578 | -8.68974 |

***Development - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_t \text{ for } i=2, r=1, k=1 \quad (37)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| | |
|---|---|
| Mean of dependent variable = 4551.52 | Adjusted R-squared = .831070 |
| Std. dev. of dependent var. = 3219.64 | Durbin-Watson statistic = 2.11701 |
| Sum of squared residuals = .280183E+08 | F-statistic (zero slopes) = 45.2765 |
| Variance of residuals = .175115E+07 | Schwarz Bayes. Info. Crit. = 14.6688 |
| Std. error of regression = 1323.31 | Log of likelihood function = -161.897 |
| R-squared = .849840 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 6270.97 | 500.442 | 12.5309 |
| m1 | .045432 | .010686 | 4.25149 |
| m2 | -3616.69 | 710.110 | -5.09314 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM81_t + m3_{i,r,k}*DUM86_t \text{ for } i=2, r=1, k=2 \quad (38)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

| | |
|---|---|
| Mean of dependent variable = 4893.77 | Adjusted R-squared = .870967 |
| Std. dev. of dependent var. = 1989.21 | Durbin-Watson statistic = 2.08449 |
| Sum of squared residuals = .816924E+07 | F-statistic (zero slopes) = 43.7499 |
| Variance of residuals = 510578. | Schwarz Bayes. Info. Crit. = 13.5193 |
| Std. error of regression = 714.547 | Log of likelihood function = -157.580 |
| R-squared = .891341 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 3710.40 | 625.928 | 5.92784 |
| m1 | .552121E-02 | .244011E-02 | 2.26268 |
| m2 | 1811.21 | 655.063 | 2.76494 |
| m3 | -3506.48 | 554.461 | -6.32412 |

***Exploration - Unconventional Gas Recovery***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM86_t + m3_{i,r,k}*DUMYR81 \quad (39)$$
$$\text{for } i=1, r=1, k=UGR$$

where DUMYR81 = 1 if year=1981
= 0 otherwise

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

| | |
|---|---|
| Mean of dependent variable = 97.2941 | Adjusted R-squared = .782890 |
| Std. dev. of dependent var. = 101.558 | Durbin-Watson statistic = 1.60088 |
| Sum of squared residuals = 29110.8 | F-statistic (zero slopes) = 20.2318 |
| Variance of residuals = 2239.29 | Schwarz Bayes. Info. Crit. = 8.11229 |
| Std. error of regression = 47.3211 | Log of likelihood function = -87.4100 |
| R-squared = .823598 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 58.6108 | 48.9271 | 1.19792 |
| m1 | .548729E-05 | .267585E-05 | 2.05067 |
| m2 | -83.7006 | 31.1441 | -2.68753 |
| m3 | 206.379 | 51.0074 | 4.04606 |

***Development - Unconventional Gas Recovery***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_t \text{ for } i=2, r=1, k=UGR \quad (40)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 10 to 25
Number of observations: 16

| | |
|---|---|
| Mean of dependent variable = 4100.28 | Adjusted R-squared = .942338 |
| Std. dev. of dependent var. = 1667.72 | Durbin-Watson statistic = 1.82614 |
| Sum of squared residuals = .208490E+07 | F-statistic (zero slopes) = 123.567 |
| Variance of residuals = 160377. | Schwarz Bayes. Info. Crit. = 12.2975 |
| Std. error of regression = 400.471 | Log of likelihood function = -116.924 |
| R-squared = .950026 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 4138.82 | 391.159 | 10.5809 |
| m1 | .146530E-02 | .317006E-03 | 4.62233 |
| m2 | -2247.87 | 263.706 | -8.52415 |

## Onshore Region 2

***Exploration - Oil***

$$\begin{aligned} WELLSON_{i,r,k,t} = {} & m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} \\ & - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1}); \text{ for } i=1, r=2, k=1 \end{aligned} \quad (41)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 19 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 50.9760 | Mean of dependent variable = 578.179 |
| Std. dev. of dependent var. = 163.320 | Std. dev. of dependent var. = 328.873 |
| Sum of squared residuals = 214067. | Sum of squared residuals = 247557. |
| Variance of residuals = 13379.2 | Variance of residuals = 15472.3 |
| Std. error of regression = 115.668 | Std. error of regression = 124.388 |
| R-squared = .567072 | R-squared = .873866 |
| Adjusted R-squared = .512956 | Adjusted R-squared = .858099 |
| Durbin-Watson statistic = 1.83108 | Durbin-Watson statistic = 1.60339 |
| ρ (autocorrelation coef.) = .887713 | |
| Standard error of ρ = .100504 | |
| t-statistic for ρ = 8.83260 | |
| F-statistic (zero slopes) = 9.94285 | |
| Log of likelihood function = -116.367 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 492.102 | 193.719 | 2.54028 |
| m1 | .552954E-04 | .184639E-04 | 2.99479 |
| m2 | -264.707 | 115.826 | -2.28539 |

***Exploration - Shallow Gas***

$$LWELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + \rho_{i,r,k}*LWELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1}); \text{ for } i=1,\ r=2,\ k=2 \quad (42)$$

where LWELLSON = natural logarithm of WELLSON

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 4 ITERATIONS

Dependent variable: LWELLSON
Current sample: 9 to 25
Number of observations: 17

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = .290929 | Mean of dependent variable = 6.71611 |
| Std. dev. of dependent var. = .464655 | Std. dev. of dependent var. = .483863 |
| Sum of squared residuals = .401998 | Sum of squared residuals = .836491 |
| Variance of residuals = .026800 | Variance of residuals = .055766 |
| Std. error of regression = .163707 | Std. error of regression = .236148 |
| R-squared = .928326 | R-squared = .790539 |
| Adjusted R-squared = .923547 | Adjusted R-squared = .776575 |
| Durbin-Watson statistic = 1.68888 | Durbin-Watson statistic = 1.47227 |
| ρ (autocorrelation coef.) = .962972 | |
| Standard error of ρ = .048235 | |
| t-statistic for ρ = 19.9641 | |
| F-statistic (zero slopes) = 113.899 | |
| Log of likelihood function = 6.39566 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 6.31729 | .562291 | 11.2349 |
| m1 | .539980E-07 | .219397E-07 | 2.46120 |

*Exploration - Deep Gas*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DCFON_{i,r,k,t-1} + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DCFON_{i,r,k,t-2}); \text{ for } i=1, r=2, k=3 \quad (43)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 3 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 1.07045 | Mean of dependent variable = 418.744 |
| Std. dev. of dependent var. = 100.179 | Std. dev. of dependent var. = 242.552 |
| Sum of squared residuals = 65481.1 | Sum of squared residuals = 127145. |
| Variance of residuals = 4092.57 | Variance of residuals = 7946.55 |
| Std. error of regression = 63.9732 | Std. error of regression = 89.1435 |
| R-squared = .699376 | R-squared = .886181 |
| Adjusted R-squared = .661798 | Adjusted R-squared = .871954 |
| Durbin-Watson statistic = 1.36171 | Durbin-Watson statistic = .968016 |
| ρ (autocorrelation coef.) = .964903 | |
| Standard error of ρ = .045879 | |
| t-statistic for ρ = 21.0315 | |
| F-statistic (zero slopes) = 14.0701 | |
| Log of likelihood function = -105.675 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 98.4664 | 219.878 | .447822 |
| m1 | .905676E-06 | .364538E-06 | 2.48445 |
| m2 | .175420E-05 | .374863E-06 | 4.67957 |

*Development - Oil*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM86_{t} + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_{t-1}); \text{ for } i=2, r=2, k=1 \quad (44)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 13 ITERATIONS

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 913.946 | Mean of dependent variable = 4115.80 |
| Std. dev. of dependent var. = 1414.39 | Std. dev. of dependent var. = 2662.30 |
| Sum of squared residuals = .182526E+08 | Sum of squared residuals = .190502E+08 |
| Variance of residuals = .107368E+07 | Variance of residuals = .112060E+07 |
| Std. error of regression = 1036.19 | Std. error of regression = 1058.58 |
| R-squared = .523560 | R-squared = .873373 |

| | |
|---|---|
| Adjusted R-squared = .467508 | Adjusted R-squared = .858476 |
| Durbin-Watson statistic = 2.01870 | Durbin-Watson statistic = 1.97211 |
| ρ (autocorrelation coef.) = .774502 | |
| Standard error of ρ = .139630 | |
| t-statistic for ρ = 5.54682 | |
| F-statistic (zero slopes) = 9.20067 | |
| Log of likelihood function = -166.078 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 3594.26 | 1312.71 | 2.73803 |
| m1 | .263859E-02 | .124767E-02 | 2.11482 |
| m2 | -2644.80 | 1072.59 | -2.46581 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM7879_{t} + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM7879_{t-1}) \text{ for } i=2,\ r=2,\ k=2 \quad (45)$$

where: DUM7879 = 1 if year=1978 or 1979
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 14 ITERATIONS

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 83.3390 | Mean of dependent variable = 1318.06 |
| Std. dev. of dependent var. = 361.039 | Std. dev. of dependent var. = 624.713 |
| Sum of squared residuals = 824480. | Sum of squared residuals = .123653E+07 |
| Variance of residuals = 58891.4 | Variance of residuals = 88323.5 |
| Std. error of regression = 242.676 | Std. error of regression = 297.193 |
| R-squared = .645952 | R-squared = .806372 |
| Adjusted R-squared = .595373 | Adjusted R-squared = .778711 |
| Durbin-Watson statistic = 1.82929 | Durbin-Watson statistic = 1.61613 |
| ρ (autocorrelation coef.) = .897900 | |
| Standard error of ρ = .114431 | |
| t-statistic for ρ = 7.84666 | |
| F-statistic (zero slopes) = 10.7071 | |
| Log of likelihood function = -116.651 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 439.168 | 559.750 | .784577 |
| m1 | .546819E-03 | .249344E-03 | 2.19303 |
| m2 | 963.871 | 300.446 | 3.20814 |

***Development - Deep Gas***

$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}$*DCFONi,r,k,t for i=2, r=2, k=3 (46)

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

Mean of dependent variable = 850.763 Adjusted R-squared = .608417
Std. dev. of dependent var. = 257.110 Durbin-Watson statistic = 1.29876
Sum of squared residuals = 440057. F-statistic (zero slopes) = 28.9673
Variance of residuals = 25885.7 Schwarz Bayes. Info. Crit. = 10.3602
Std. error of regression = 160.890 Log of likelihood function = -122.437
R-squared = .630172

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 361.371 | 98.1351 | 3.68239 |
| m1 | .294014E-04 | .546279E-05 | 5.38213 |

***Exploration - Unconventional Gas Discovery***

$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t}$ for i=1, r=2, k=UGR (47)

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 9 to 24
Number of observations: 16

Mean of dependent variable = 27.5406 Adjusted R-squared = .580925
Std. dev. of dependent var. = 25.1012 Durbin-Watson statistic = 1.57623
Sum of squared residuals = 3696.66 F-statistic (zero slopes) = 21.7931
Variance of residuals = 264.047 Schwarz Bayes. Info. Crit. = 5.78917
Std. error of regression = 16.2495 Log of likelihood function = -66.2438
R-squared = .608863

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | -17.5337 | 10.4752 | -1.67383 |
| m1 | .950512E-06 | .203609E-06 | 4.66831 |

***Development - Unconventional Gas Recovery***

$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM89_t$ for i=2, r=2, k=UGR (48)

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 12 to 25
Number of observations: 14

Mean of dependent variable = 892.052 Adjusted R-squared = .464715

Std. dev. of dependent var. = 369.999 Durbin-Watson statistic = 1.57795
Sum of squared residuals = 806083. F-statistic (zero slopes) = 6.64306
Variance of residuals = 73280.2 Schwarz Bayes. Info. Crit. = 11.5264
Std. error of regression = 270.703 Log of likelihood function = -96.5913
R-squared = .547066

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | -144.879 | 386.996 | -.374369 |
| m1 | .176912E-03 | .771963E-04 | 2.29172 |
| m2 | 954.959 | 277.512 | 3.44114 |

## Onshore Region 3

***Exploration - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1}) \text{ for } i=1, r=3, k=1 \quad (49)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 12 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

(Statistics based on transformed data)
Mean of dependent variable = 184.224
Std. dev. of dependent var. = 390.329
Sum of squared residuals = .163242E+07
Variance of residuals = 102026.
Std. error of regression = 319.416
R-squared = .405137
Adjusted R-squared = .330779
Durbin-Watson statistic = 1.75110
ρ (autocorrelation coef.) = .848395
Standard error of ρ = .115756
t-statistic for ρ = 7.32916
F-statistic (zero slopes) = 5.43975
Log of likelihood function = -135.527

(Statistics based on original data)
Mean of dependent variable = 1281.39
Std. dev. of dependent var. = 670.085
Sum of squared residuals = .163789E+07
Variance of residuals = 102368.
Std. error of regression = 319.950
R-squared = .807411
Adjusted R-squared = .783337
Durbin-Watson statistic = 1.75233

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 1120.01 | 451.245 | 2.48204 |
| m1 | .242086E-03 | .122333E-03 | 1.97891 |
| m2 | -717.874 | 316.010 | -2.27168 |

***Exploration - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t} + m2_{i,r,k}*DUM7879_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM7879_{t-1}) \text{ for } i=1, r=3, k=2 \quad (50)$$

where DUM7879 = 1 if year=1978 or 1979
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 10 ITERATIONS

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 36.3570 | Mean of dependent variable = 467.829 |
| Std. dev. of dependent var. = 108.646 | Std. dev. of dependent var. = 153.059 |
| Sum of squared residuals = 75985.1 | Sum of squared residuals = 99026.7 |
| Variance of residuals = 5427.51 | Variance of residuals = 7073.33 |
| Std. error of regression = 73.6716 | Std. error of regression = 84.1031 |
| R-squared = .626373 | R-squared = .745317 |
| Adjusted R-squared = .572997 | Adjusted R-squared = .708933 |
| Durbin-Watson statistic = 2.28378 | Durbin-Watson statistic = 2.00273 |
| ρ (autocorrelation coef.) = .908559 | |
| Standard error of ρ = .095672 | |
| t-statistic for ρ = 9.49656 | |
| F-statistic (zero slopes) = 10.3987 | |
| Log of likelihood function = -96.4380 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 335.634 | 142.771 | 2.35085 |
| m1 | .690004E-04 | .283589E-04 | 2.43311 |
| m2 | 180.270 | 74.9592 | 2.40491 |

***Exploration - Deep Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_{t} \text{ for } i=1, r=3, k=3 \qquad (51)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| | |
|---|---|
| Mean of dependent variable = 60.0411 | Adjusted R-squared = .688687 |
| Std. dev. of dependent var. = 51.7632 | Durbin-Watson statistic = 1.67708 |
| Sum of squared residuals = 13346.2 | F-statistic (zero slopes) = 20.9098 |
| Variance of residuals = 834.139 | Schwarz Bayes. Info. Crit. = 7.01946 |
| Std. error of regression = 28.8815 | Log of likelihood function = -89.2281 |
| R-squared = .723278 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 43.0646 | 20.8098 | 2.06944 |
| m1 | .481000E-06 | .156471E-06 | 3.07405 |
| m2 | -50.1844 | 15.6178 | -3.21329 |

***Development - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*RDCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM8084_{t} + m3_{i,r,k}*DUM86_{t}$$
$$+ \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*RDCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM8084_{t-1}$$

$$+ m3_{i,r,k}*DUM86_{t-1}) \text{ for } i=2, r=3, k=1 \tag{52}$$

where, DUM8084 = 1 if 1980≤year≤1984
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 16 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 1254.42 | Mean of dependent variable = 6668.41 |
| Std. dev. of dependent var. = 2302.35 | Std. dev. of dependent var. = 4963.80 |
| Sum of squared residuals = .274369E+08 | Sum of squared residuals = .277755E+08 |
| Variance of residuals = .182913E+07 | Variance of residuals = .185170E+07 |
| Std. error of regression = 1352.45 | Std. error of regression = 1360.77 |
| R-squared = .713033 | R-squared = .944398 |
| Adjusted R-squared = .655639 | Adjusted R-squared = .933277 |
| Durbin-Watson statistic = 1.46532 | Durbin-Watson statistic = 1.46513 |
| ρ (autocorrelation coef.) = .801021 | |
| Standard error of ρ = .143550 | |
| t-statistic for ρ = 5.58009 | |
| F-statistic (zero slopes) = 12.3880 | |
| Log of likelihood function = -162.211 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 5358.74 | 1921.25 | 2.78919 |
| m1 | .347973E-02 | .191828E-02 | 1.81399 |
| m2 | 3564.53 | 1036.77 | 3.43810 |
| m3 | -5103.19 | 1313.68 | -3.88465 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM7882_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1}$$
$$- \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM7882_{t-1}) \text{ for } i=2, r=3, k=2 \tag{53}$$

where: DUM7882 = 1 if 1978≤year≤1982
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 16 ITERATIONS

Dependent variable: WELLSON
Current sample: 10 to 25
Number of observations: 16

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 625.842 | Mean of dependent variable = 2345.23 |
| Std. dev. of dependent var. = 585.432 | Std. dev. of dependent var. = 868.730 |
| Sum of squared residuals = .125650E+07 | Sum of squared residuals = .135129E+07 |

| | |
|---|---|
| Variance of residuals = 96653.7 | Variance of residuals = 103945. |
| Std. error of regression = 310.892 | Std. error of regression = 322.405 |
| R-squared = .762901 | R-squared = .884064 |
| Adjusted R-squared = .726425 | Adjusted R-squared = .866228 |
| Durbin-Watson statistic = 1.82075 | Durbin-Watson statistic = 1.76827 |
| ρ (autocorrelation coef.) = .737068 | |
| Standard error of ρ = .178914 | |
| t-statistic for ρ = 4.11969 | |
| F-statistic (zero slopes) = 20.0947 | |
| Log of likelihood function = -113.265 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 1077.27 | 503.879 | 2.13795 |
| m1 | .109779E-02 | .489915E-03 | 2.24078 |
| m2 | 1252.13 | 310.462 | 4.03313 |

***Development - Deep Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUMYR82_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUMYR82_{t-1}) \text{ for } i=2, r=3, k=3 \quad (54)$$

where: DUMYR82 = 1 if year=1982
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 13 ITERATIONS

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 103.761 | Mean of dependent variable = 425.178 |
| Std. dev. of dependent var. = 138.353 | Std. dev. of dependent var. = 194.492 |
| Sum of squared residuals = 69614.0 | Sum of squared residuals = 69681.5 |
| Variance of residuals = 4094.94 | Variance of residuals = 4098.91 |
| Std. error of regression = 63.9917 | Std. error of regression = 64.0227 |
| R-squared = .808622 | R-squared = .906735 |
| Adjusted R-squared = .786107 | Adjusted R-squared = .895762 |
| Durbin-Watson statistic = 2.29982 | Durbin-Watson statistic = 2.30451 |
| ρ (autocorrelation coef.) = .764800 | |
| Standard error of ρ = .142456 | |
| t-statistic for ρ = 5.36868 | |
| F-statistic (zero slopes) = 35.9068 | |
| Log of likelihood function = -110.368 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 247.042 | 68.2949 | 3.61728 |
| m1 | .164939E-04 | .555119E-05 | 2.97124 |
| m2 | 438.168 | 52.6968 | 8.31489 |

### *Development - Unconventional Gas Recovery*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM90_{t} \text{ for } i=2, r=3, k=UGR \quad (55)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 10 to 25
Number of observations: 16

| | |
|---|---|
| Mean of dependent variable = 95.0350 | Adjusted R-squared = .723690 |
| Std. dev. of dependent var. = 68.3073 | Durbin-Watson statistic = 2.51509 |
| Sum of squared residuals = 16760.0 | F-statistic (zero slopes) = 20.6434 |
| Variance of residuals = 1289.23 | Schwarz Bayes. Info. Crit. = 7.47402 |
| Std. error of regression = 35.9059 | Log of likelihood function = -78.3363 |
| R-squared = .760531 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | -77.3680 | 41.2445 | -1.87584 |
| m1 | .300529E-04 | .855264E-05 | 3.51388 |
| m2 | 189.624 | 31.0855 | 6.10008 |

## Onshore Region 4

### *Exploration - Oil*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_{t} + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1}) \text{ for } i=1, r=4, k=1 \quad (56)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 9 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 156.837 | Mean of dependent variable = 1116.59 |
| Std. dev. of dependent var. = 298.363 | Std. dev. of dependent var. = 599.565 |
| Sum of squared residuals = 579217. | Sum of squared residuals = 583815. |
| Variance of residuals = 36201.1 | Variance of residuals = 36488.4 |
| Std. error of regression = 190.266 | Std. error of regression = 191.019 |
| R-squared = .639044 | R-squared = .914117 |
| Adjusted R-squared = .593925 | Adjusted R-squared = .903381 |
| Durbin-Watson statistic = 1.48492 | Durbin-Watson statistic = 1.45805 |
| ρ (autocorrelation coef.) = .854344 | |
| Standard error of ρ = .106268 | |
| t-statistic for ρ = 8.03949 | |
| F-statistic (zero slopes) = 14.1315 | |
| Log of likelihood function = -125.702 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 1469.04 | 255.863 | 5.74152 |
| m1 | .281248E-03 | .123058E-03 | 2.28549 |
| m2 | -900.065 | 194.904 | -4.61799 |

***Exploration - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM85_{t} \text{ for } i=1, r=4, k=2 \tag{57}$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 10 to 25
Number of observations: 16

Mean of dependent variable = 516.826
Std. dev. of dependent var. = 360.595
Sum of squared residuals = 103552.
Variance of residuals = 7965.56
Std. error of regression = 89.2500
R-squared = .946908
Adjusted R-squared = .938740
Durbin-Watson statistic = 2.56696
F-statistic (zero slopes) = 115.929
Schwarz Bayes. Info. Crit. = 9.29510
Log of likelihood function = -92.9050

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 378.188 | 109.655 | 3.44889 |
| m1 | .428057E-04 | .805426E-05 | 5.31467 |
| m2 | -424.385 | 63.6438 | -6.66813 |

***Exploration - Deep Gas***

$$\begin{aligned} WELLSON_{i,r,k,t} &= m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_{t} + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} \\ &- \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1}) \text{ for } i=1, r=4, k=3 \end{aligned} \tag{58}$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 23 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

(Statistics based on transformed data)
Mean of dependent variable = 33.2803
Std. dev. of dependent var. = 31.9699
Sum of squared residuals = 5234.93
Variance of residuals = 327.183
Std. error of regression = 18.0882
R-squared = .715699
Adjusted R-squared = .680161
Durbin-Watson statistic = 2.14062
ρ (autocorrelation coef.) = .374199
Standard error of ρ = .225739
t-statistic for ρ = 1.65766
F-statistic (zero slopes) = 20.1148
Log of likelihood function = -80.4126

(Statistics based on original data)
Mean of dependent variable = 52.8573
Std. dev. of dependent var. = 42.3253
Sum of squared residuals = 5257.49
Variance of residuals = 328.593
Std. error of regression = 18.1271
R-squared = .837122
Adjusted R-squared = .816763
Durbin-Watson statistic = 2.12439

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 61.2385 | 16.3263 | 3.75091 |
| m1 | .212647E-06 | .107335E-06 | 1.98115 |
| m2 | -57.7438 | 12.6416 | -4.56774 |

***Development - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM86_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1}) \text{ for i=2, r=4, k=1} \quad (59)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 7 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

(Statistics based on transformed data)
Mean of dependent variable = 633.819
Std. dev. of dependent var. = 1721.41
Sum of squared residuals = .125408E+08
Variance of residuals = 783797.
Std. error of regression = 885.323
R-squared = .767713
Adjusted R-squared = .738677
Durbin-Watson statistic = 1.36631
ρ (autocorrelation coef.) = .890354
Standard error of ρ = .087538
t-statistic for ρ = 10.1711
F-statistic (zero slopes) = 26.0258
Log of likelihood function = -155.047

(Statistics based on original data)
Mean of dependent variable = 6418.00
Std. dev. of dependent var. = 3404.48
Sum of squared residuals = .135133E+08
Variance of residuals = 844582.
Std. error of regression = 919.011
R-squared = .940231
Adjusted R-squared = .932760
Durbin-Watson statistic = 1.35150

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 8339.79 | 1435.89 | 5.80809 |
| m1 | .928734E-02 | .316049E-02 | 2.93858 |
| m2 | -6017.91 | 908.578 | -6.62344 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM7882_t + m3_{i,r,k}*DUM86_t + m4_{i,r,k}*DUM9093_t \text{ for i=2, r=4, k=2} \quad (60)$$

where: DUM7882 = 1 if 1978≤year≤1982
= 0 otherwise
DUM9093 = 1 if 1990≤year≤1993
= 0 otherwise

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 10 to 25
Number of observations: 16

Mean of dependent variable = 667.761 Adjusted R-squared = .987616
Std. dev. of dependent var. = 403.869 Durbin-Watson statistic = 2.07656
Sum of squared residuals = 22219.4 F-statistic (zero slopes) = 300.063
Variance of residuals = 2019.94 Schwarz Bayes. Info. Crit. = 8.10257
Std. error of regression = 44.9438 Log of likelihood function = -80.5921
R-squared = .990918

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 813.092 | 80.9639 | 10.0427 |
| m1 | .365198E-04 | .203745E-04 | 1.79242 |
| m2 | 270.708 | 37.7521 | 7.17067 |
| m3 | -464.945 | 42.3386 | -10.9816 |
| m4 | -221.335 | 30.1622 | -7.33818 |

***Development - Deep Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM8385_t + m3_{i,r,k}*DUM86_t \text{ for } i=2, r=4, k=3 \quad (61)$$

where: DUM8385 = 1 if 1983≤year≤1985
= 0 otherwise

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

Mean of dependent variable = 94.0929 Adjusted R-squared = .973196
Std. dev. of dependent var. = 62.8703 Durbin-Watson statistic = 1.56667
Sum of squared residuals = 1589.23 F-statistic (zero slopes) = 218.845
Variance of residuals = 105.948 Schwarz Bayes. Info. Crit. = 5.04645
Std. error of regression = 10.2931 Log of likelihood function = -69.0122
R-squared = .977663

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 155.545 | 9.48859 | 16.3928 |
| m1 | .156322E-05 | .543800E-06 | 2.87463 |
| m2 | -100.057 | 7.61023 | -13.1477 |
| m3 | -128.569 | 5.78378 | -22.2292 |

***Development - Unconventional Gas Recovery***

$$\begin{aligned}WELLSON_{i,r,k,t} &= m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM90_t + m3_{i,r,k}*DUMYR82_t \\ &+ \rho_{i,r,k}*WELLSON_{i,r,k,t-10} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM86_{t-1} \\ &+ m3_{i,r,k}*DUMYR82_{t-1}) \text{ for } i=2, r=4, k=UGR \quad (62)\end{aligned}$$

where: DUMYR82 = 1 if year=1982
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 14 ITERATIONS

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 161.511 | Mean of dependent variable = 316.110 |
| Std. dev. of dependent var. = 148.328 | Std. dev. of dependent var. = 200.805 |
| Sum of squared residuals = 128129. | Sum of squared residuals = 132906. |
| Variance of residuals = 9856.04 | Variance of residuals = 10223.6 |
| Std. error of regression = 99.2776 | Std. error of regression = 101.112 |
| R-squared = .639546 | R-squared = .796948 |
| Adjusted R-squared = .556364 | Adjusted R-squared = .750089 |
| Durbin-Watson statistic = 1.24980 | Durbin-Watson statistic = 1.20533 |
| ρ (autocorrelation coef.) = .538803 | |
| Standard error of ρ = .255978 | |
| t-statistic for ρ = 2.10488 | |
| F-statistic (zero slopes) = 7.57201 | |
| Log of likelihood function = -100.178 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | -144.742 | 139.211 | -1.03973 |
| m1 | .273249E-04 | .928213E-05 | 2.94382 |
| m2 | 272.224 | 87.7404 | 3.10261 |
| m3 | 351.984 | 87.9703 | 4.00117 |

## Onshore Region 5

### *Exploration - Oil*

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM86_t \text{ for } i=1, r=5, k=1 \quad (63)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

Mean of dependent variable = 803.459
Std. dev. of dependent var. = 458.389
Sum of squared residuals = .119303E+07
Variance of residuals = 70178.3
Std. error of regression = 264.912
R-squared = .701166
Adjusted R-squared = .666009
Durbin-Watson statistic = 1.52526
F-statistic (zero slopes) = 19.9438
Schwarz Bayes. Info. Crit. = 11.4456
Log of likelihood function = -138.342

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 553.693 | 193.150 | 2.86665 |
| m1 | .146690E-03 | .448117E-04 | 3.27347 |
| m2 | -356.496 | 146.732 | -2.42958 |

***Exploration - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t} + m2_{i,r,k}*DUM82_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*OSGDCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM82_{t-1}) \text{ for } i=1, r=5, k=2 \quad (64)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 10 ITERATIONS

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 9.04308 | Mean of dependent variable = 394.498 |
| Std. dev. of dependent var. = 116.207 | Std. dev. of dependent var. = 250.492 |
| Sum of squared residuals = 53632.9 | Sum of squared residuals = 84671.4 |
| Variance of residuals = 3830.92 | Variance of residuals = 6047.96 |
| Std. error of regression = 61.8944 | Std. error of regression = 77.7686 |
| R-squared = .777747 | R-squared = .922847 |
| Adjusted R-squared = .745997 | Adjusted R-squared = .911825 |
| Durbin-Watson statistic = 1.58974 | Durbin-Watson statistic = 1.56072 |
| ρ (autocorrelation coef.) = .933898 | |
| Standard error of ρ = .079714 | |
| t-statistic for ρ = 11.7156 | |
| F-statistic (zero slopes) = 21.2001 | |
| Log of likelihood function = -93.6325 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 508.964 | 152.236 | 3.34326 |
| m1 | .298261E-04 | .114736E-04 | 2.59955 |
| m2 | -299.552 | 62.8327 | -4.76745 |

***Exploration - Deep Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM86_t \text{ for } i=1, r=5, k=3 \quad (65)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

| | |
|---|---|
| Mean of dependent variable = 58.7138 | Adjusted R-squared = .561653 |
| Std. dev. of dependent var. = 40.9395 | Durbin-Watson statistic = 1.94207 |
| Sum of squared residuals = 12489.7 | F-statistic (zero slopes) = 13.1723 |
| Variance of residuals = 734.688 | Schwarz Bayes. Info. Crit. = 6.88629 |
| Std. error of regression = 27.1051 | Log of likelihood function = -92.7480 |
| R-squared = .607795 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 78.0125 | 9.78859 | 7.96974 |
| m1 | .994387E-06 | .500750E-06 | 1.98580 |
| m2 | -53.1020 | 12.3111 | -4.31335 |

***Development - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM86_t \text{ for } i=2, r=5, k=1 \quad (66)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

Mean of dependent variable = 1378.85
Std. dev. of dependent var. = 810.691
Sum of squared residuals = .182260E+07
Variance of residuals = 107212.
Std. error of regression = 327.432
R-squared = .854042
Adjusted R-squared = .836871
Durbin-Watson statistic = 1.53379
F-statistic (zero slopes) = 49.7361
Schwarz Bayes. Info. Crit. = 11.8694
Log of likelihood function = -142.579

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 969.347 | 307.349 | 3.15390 |
| m1 | .147764E-02 | .393721E-03 | 3.75300 |
| m2 | -754.369 | 216.550 | -3.48358 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM8389_t + m3_{i,r,k}*DUM9093_t + m4_{i,r,k}*DUMYR94_t \text{ for } i=2, r=5, k=2 \quad (67)$$

where: DUM8389 = 1 if 1983≤year≤1989
= 0 otherwise
DUM9093 = 1 if 1990≤year≤1993
= 0 otherwise
DUMYR94 = 1 if year=1995
= 0 otherwise

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

Mean of dependent variable = 329.812
Std. dev. of dependent var. = 139.694
Sum of squared residuals = 25472.6
Variance of residuals = 2122.71
Std. error of regression = 46.0729
R-squared = .918418
Adjusted R-squared = .891224
Durbin-Watson statistic = 2.27422
F-statistic (zero slopes) = 33.7727
Schwarz Bayes. Info. Crit. = 8.14544
Log of likelihood function = -86.2752

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 299.323 | 51.8957 | 5.76777 |

| | | | |
|---|---|---|---|
| m1 | 100521E-03 | .468531E-04 | 2.14544 |
| m2 | -202.188 | 27.2638 | -7.41599 |
| m3 | 91.6662 | 31.0224 | 2.95484 |
| m4 | -265.491 | 50.8389 | -5.22220 |

**Development - Deep Gas**

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM92_t \text{ for } i=2, r=5, k=3 \quad (68)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26
Number of observations: 20

Mean of dependent variable = 96.2216
Std. dev. of dependent var. = 54.2114
Sum of squared residuals = 14414.5
Variance of residuals = 847.914
Std. error of regression = 29.1190
R-squared = .741854
Adjusted R-squared = .711484
Durbin-Watson statistic = 1.43575
F-statistic (zero slopes) = 24.4271
Schwarz Bayes. Info. Crit. = 7.02962
Log of likelihood function = -94.1814

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 64.2118 | 8.12141 | 7.90648 |
| m1 | .114397E-04 | .342764E-05 | 3.33749 |
| m2 | 96.9988 | 16.3023 | 5.95001 |

***Exploration - Unconventional Gas Recovery***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DUM9091_t + m3_{i,r,k}*DUM9293_t \quad (69)$$
for i=1, r=5, k=UGR

where: DUM9091 = 1 if year=1990 or 1991
= 0 otherwise
DUM9293 = 1 if year=1992 or 1993
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 10 ITERATIONS

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

(Statistics based on transformed data)
Mean of dependent variable = 6.01286
Std. dev. of dependent var. = 7.82874
Sum of squared residuals = 233.420
Variance of residuals = 17.9554
Std. error of regression = 4.23738
R-squared = .762276
Adjusted R-squared = .707416

(Statistics based on original data)
Mean of dependent variable = 14.7004
Std. dev. of dependent var. = 12.0415
Sum of squared residuals = 234.949
Variance of residuals = 18.0730
Std. error of regression = 4.25124
R-squared = .898784
Adjusted R-squared = .875427

Durbin-Watson statistic = 1.34539 Durbin-Watson statistic = 1.34536
ρ (autocorrelation coef.) = .605037
Standard error of ρ = .202609
t-statistic for ρ = 2.98623
F-statistic (zero slopes) = 13.8716
Log of likelihood function = -46.6167

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 2.80910 | 4.44336 | .632201 |
| m1 | .270761E-06 | .137815E-06 | 1.96467 |
| m2 | 21.7902 | 4.03632 | 5.39853 |
| m3 | 11.7959 | 3.86579 | 3.05135 |

***Development - Unconventional Gas Recovery***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}{*}DCFON_{i,r,k,t} + m2_{i,r,k}{*}DUM83_t{*}DCFON_{i,r,k,t} + m3_{i,r,k}{*}DUM83_t \qquad (70)$$

for I=2, r=5, k=UGR

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 9 to 25
Number of observations: 17

Mean of dependent variable = 1095.75 Adjusted R-squared = .787100
Std. dev. of dependent var. = 328.759 Durbin-Watson statistic = 2.11607
Sum of squared residuals = 299140. F-statistic (zero slopes) = 20.7176
Variance of residuals = 23010.8 Schwarz Bayes. Info. Crit. = 10.4421
Std. error of regression = 151.693 Log of likelihood function = -107.213
R-squared = .827019

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 1055.87 | 113.688 | 9.28746 |
| m1 | .297229E-03 | .838416E-04 | 3.54513 |
| m2 | .165803E-02 | .271106E-03 | 6.11579 |
| m3 | -593.663 | 86.6633 | -6.85023 |

## Onshore Region 6

***Exploration - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}{*}DCFON_{i,r,k,t} + m2_{i,r,k}{*}DUM8392_t + m3_{i,r,k}{*}DUM93_t + m4_{i,r,k}{*}TREND7782_t \text{ for i=1, r=6, k=1} \qquad (71)$$

where: DUM8392 = 1 if $1983 \leq \text{year} \leq 1992$
= 0 otherwise
TREND7782 = year, if $1977 \leq \text{year} \leq 1982$
= 0 otherwise

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 7 to 26

Number of observations: 20

| | |
|---|---|
| Mean of dependent variable = 110.850 | Adjusted R-squared = .937400 |
| Std. dev. of dependent var. = 106.821 | Durbin-Watson statistic = 1.97323 |
| Sum of squared residuals = 10714.7 | F-statistic (zero slopes) = 72.1281 |
| Variance of residuals = 714.312 | Schwarz Bayes. Info. Crit. = 7.03257 |
| Std. error of regression = 26.7266 | Log of likelihood function = -91.2151 |
| R-squared = .950579 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | -56874.7 | 11360.4 | -5.00641 |
| m1 | .400144E-04 | .126270E-04 | 3.16896 |
| m2 | 56957.3 | 11356.9 | 5.01521 |
| m3 | 56892.6 | 11358.3 | 5.00888 |
| m4 | 28.8709 | 5.73811 | 5.03144 |

***Exploration - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM83_t + m3_{i,r,k}*DUMYR94_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1} - \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM83_{t-1} + m3_{i,r,k}*DUMYR94_{t-1}) \text{ for } i=1, r=6, k=2 \quad (72)$$

where: DUMYR94 = 1 if year=1994
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 8 ITERATIONS

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 30.4432 | Mean of dependent variable = 104.432 |
| Std. dev. of dependent var. = 33.7558 | Std. dev. of dependent var. = 54.6365 |
| Sum of squared residuals = 6285.82 | Sum of squared residuals = 6380.30 |
| Variance of residuals = 419.055 | Variance of residuals = 425.353 |
| Std. error of regression = 20.4708 | Std. error of regression = 20.6241 |
| R-squared = .694541 | R-squared = .881533 |
| Adjusted R-squared = .633450 | Adjusted R-squared = .857840 |
| Durbin-Watson statistic = 1.76776 | Durbin-Watson statistic = 1.76616 |
| ρ (autocorrelation coef.) = .698183 | |
| Standard error of ρ = .178873 | |
| t-statistic for ρ = 3.90323 | |
| F-statistic (zero slopes) = 11.3146 | |
| Log of likelihood function = -82.4093 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 136.070 | 19.7633 | 6.88496 |
| m1 | .209819E-05 | .933000E-06 | 2.24886 |
| m2 | -98.7458 | 20.9826 | -4.70609 |
| m3 | -38.7112 | 18.2004 | -2.12695 |

***Development - Oil***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t} + m2_{i,r,k}*DCFON_{i,r,k,t-1} + m3_{i,r,k}*DUM92_t \text{ for } i=2, r=6, k=1 \quad (73)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSON
Current sample: 8 to 26
Number of observations: 19

Mean of dependent variable = 1732.33
Std. dev. of dependent var. = 695.619
Sum of squared residuals = .191669E+07
Variance of residuals = 127779.
Std. error of regression = 357.462
R-squared = .779942
Adjusted R-squared = .735931
Durbin-Watson statistic = 1.68578
F-statistic (zero slopes) = 17.7213
Schwarz Bayes. Info. Crit. = 12.1416
Log of likelihood function = -136.416

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 2310.34 | 124.857 | 18.5039 |
| m1 | .175011E-02 | .855290E-03 | 2.04621 |
| m2 | .165857E-02 | .835621E-03 | 1.98483 |
| m3 | -1293.53 | 205.338 | -6.29953 |

***Development - Shallow Gas***

$$WELLSON_{i,r,k,t} = m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-1} + m2_{i,r,k}*DUM8485_t + m3_{i,r,k}*DUM93_t + \rho_{i,r,k}*WELLSON_{i,r,k,t-1}$$
$$- \rho_{i,r,k}*(m0_{i,r,k} + m1_{i,r,k}*DCFON_{i,r,k,t-2} + m2_{i,r,k}*DUM8485_{t-1} + m3_{i,r,k}*DUM93_{t-1}) \text{ for } i=2, r=6, k=2 \quad (74)$$

where: DUM8485 = 1 if year=1984 or 1985
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 5 ITERATIONS

Dependent variable: SGDWELLS
Current sample: 8 to 26
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 31.8524 | Mean of dependent variable = 61.8137 |
| Std. dev. of dependent var. = 30.8462 | Std. dev. of dependent var. = 40.9290 |
| Sum of squared residuals = 4338.76 | Sum of squared residuals = 4345.38 |
| Variance of residuals = 289.251 | Variance of residuals = 289.692 |
| Std. error of regression = 17.0074 | Std. error of regression = 17.0203 |
| R-squared = .746747 | R-squared = .856819 |
| Adjusted R-squared = .696097 | Adjusted R-squared = .828183 |
| Durbin-Watson statistic = 2.24495 | Durbin-Watson statistic = 2.23962 |
| ρ (autocorrelation coef.) = .490530 | |

Standard error of ρ = .211323
t-statistic for ρ = 2.32123
F-statistic (zero slopes) = 14.7369
Log of likelihood function = -78.6911

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| m0 | 11.0599 | 21.2453 | .520582 |
| m1 | .130340E-04 | .539638E-05 | 2.41531 |
| m2 | 81.1244 | 14.1906 | 5.71679 |
| m3 | -44.1830 | 14.9995 | -2.94564 |

# Offshore Well Equations

## Offshore Region 2 (Pacific Offshore)

***Development - Oil***

$$WELLSOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}*DCFOFF_{i,r,k,t} + \alpha 2_{i,r,k}*DUM86_t \text{ for i=2, r=2, k=1} \quad (75)$$

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 17 ITERATIONS

Dependent variable: WELLSOFF
Current sample: 7 to 25
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 32.2904 | Mean of dependent variable = 56.6316 |
| Std. dev. of dependent var. = 31.0380 | Std. dev. of dependent var. = 43.9990 |
| Sum of squared residuals = 10634.4 | Sum of squared residuals = 11024.2 |
| Variance of residuals = 664.653 | Variance of residuals = 689.015 |
| Std. error of regression = 25.7809 | Std. error of regression = 26.2491 |
| R-squared = .392467 | R-squared = .684425 |
| Adjusted R-squared = .316526 | Adjusted R-squared = .644978 |
| Durbin-Watson statistic = 1.95548 | Durbin-Watson statistic = 1.91825 |

ρ (autocorrelation coef.) = .433712
Standard error of ρ = .235150
t-statistic for ρ = 1.84441
F-statistic (zero slopes) = 5.04473
Log of likelihood function = -87.1745

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| α0 | 95.6359 | 16.3616 | 5.84514 |
| α1 | .821726E-05 | .444220E-05 | 1.84982 |
| α2 | -37.0291 | 19.3245 | -1.91617 |

## Offshore Region 5 (Shallow Gulf of Mexico)

***Exploration - Oil***

$$WELLSOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}*DCFOFF_{i,r,k,t-1} + \alpha 2_{i,r,k}*DUMYR82_t + \rho_{i,r,k}*WELLSOFF_{i,r,k,t-1} - \rho_{i,r,k}*(\alpha 0_{i,r,k} + \alpha 1_{i,r,k}*DCFOFF_{i,r,k,t-2} + \alpha 2_{i,r,k}*DUMYR82_{t-1}) \text{ for } i=1, r=5, k=1 \quad (76)$$

where: DUMYR82 = 1 if year=1982
= 0 otherwise

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 7 ITERATIONS

Dependent variable: WELLSOFF
Current sample: 2 to 20
Number of observations: 19

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 14.4860 | Mean of dependent variable = 30.5263 |
| Std. dev. of dependent var. = 31.3783 | Std. dev. of dependent var. = 34.0251 |
| Sum of squared residuals = 4615.01 | Sum of squared residuals = 4926.04 |
| Variance of residuals = 288.438 | Variance of residuals = 307.877 |
| Std. error of regression = 16.9835 | Std. error of regression = 17.5464 |
| R-squared = .741552 | R-squared = .768104 |
| Adjusted R-squared = .709246 | Adjusted R-squared = .739116 |
| Durbin-Watson statistic = 1.81898 | Durbin-Watson statistic = 1.79722 |
| ρ (autocorrelation coef.) = .556142 | |
| Standard error of ρ = .223749 | |
| t-statistic for ρ = 2.48556 | |
| F-statistic (zero slopes) = 22.7220 | |
| Log of likelihood function = -79.3248 | |

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| α0 | 77.7201 | 27.4389 | 2.83248 |
| α1 | .677131E-05 | .331580E-05 | 2.04214 |
| α2 | 90.3297 | 15.3075 | 5.90103 |

***Development - Oil***

$$LWELLSOFF_{i,r,k,t} = \alpha 0_{i,r,k} + \alpha 1_{i,r,k}*DCFOFF_{i,r,k,t-1} + \alpha 2_{i,r,k}*DUM83_t \text{ for } i=2, r=5, k=1 \quad (77)$$

where: LWELLSOFF = natural logarithm of WELLSOFF

Ordinary Least Squares Estimation

Dependent variable: LWELLSOFF
Current sample: 2 to 20
Number of observations: 19

| | |
|---|---|
| Mean of dependent variable = 5.41694 | Adjusted R-squared = .560168 |
| Std. dev. of dependent var. = .366851 | Durbin-Watson statistic = 2.04360 |
| Sum of squared residuals = .947079 | F-statistic (zero slopes) = 12.4623 |

Variance of residuals = .059192     Schwarz Bayes. Info. Crit. = -2.53390
Std. error of regression = .243295     Log of likelihood function = 1.52888
R-squared = .609038

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| $\alpha0$ | 7.08308 | .338540 | 20.9224 |
| $\alpha1$ | .328192E-06 | .673038E-07 | 4.87628 |
| $\alpha2$ | -.308151 | .125598 | -2.45348 |

***Exploration - Gas***

$$WELLSOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k}*DCFOFF_{i,r,k,t} + \alpha2_{i,r,k}*DUM7681_t \text{ for i=1, r=5, k=2} \quad (78)$$

Ordinary Least Squares Estimation

Dependent variable: WELLSOFF
Current sample:  1 to 20
Number of observations:  20

Mean of dependent variable = 194.550     Adjusted R-squared = .543428
Std. dev. of dependent var. = 64.5881     Durbin-Watson statistic = 1.55587
Sum of squared residuals = 32379.0     F-statistic (zero slopes) = 12.3072
Variance of residuals = 1904.65     Schwarz Bayes. Info. Crit. = 7.83889
Std. error of regression = 43.6423     Log of likelihood function = -102.274
R-squared = .591488

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| $\alpha0$ | 222.969 | 24.9078 | 8.95175 |
| $\alpha1$ | .157207E-04 | .621343E-05 | 2.53012 |
| $\alpha2$ | 109.897 | 22.5826 | 4.86643 |

***Development - Gas***

$$LWELLSOFF_{i,r,k,t} = \alpha0_{i,r,k} + \alpha1_{i,r,k}*DCFOFF_{i,r,k,t} \text{ for i=2, r=5, k=2} \quad (79)$$

where: LWELLSOFF = natural logarithm of WELLSOFF

FIRST-ORDER SERIAL CORRELATION OF THE ERROR
MAXIMUM LIKELIHOOD ITERATIVE TECHNIQUE

CONVERGENCE ACHIEVED AFTER 9 ITERATIONS

Dependent variable: LWELLSOFF
Current sample:  1 to 20
Number of observations:  20

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = 2.52060 | Mean of dependent variable = 5.81468 |
| Std. dev. of dependent var. = .584367 | Std. dev. of dependent var. = .332881 |
| Sum of squared residuals = 1.29747 | Sum of squared residuals = 1.29935 |
| Variance of residuals = .072082 | Variance of residuals = .072186 |
| Std. error of regression = .268480 | Std. error of regression = .268675 |
| R-squared = .800710 | R-squared = .400965 |
| Adjusted R-squared = .789639 | Adjusted R-squared = .367686 |
| Durbin-Watson statistic = 1.86208 | Durbin-Watson statistic = 1.84904 |

$\rho$ (autocorrelation coef.) = .583597
Standard error of $\rho$ = .177912
t-statistic for $\rho$ = 3.28025
F-statistic (zero slopes) = 72.0118
Log of likelihood function = -1.23382

| Parameter | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| $\alpha 0$ | 6.19373 | .216745 | 28.5762 |
| $\alpha 1$ | .136607E-06 | .551807E-07 | 2.47562 |

# 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. Option 1 employs the price elasticity estimates that are passed from the OGSM to the PMM and NGTDM. Options 2 and 3 employ econometrically estimated alternative to the elasticity approach.  The section below documents the estimations.

## Option 1

### *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:

$$\begin{aligned} LCRUDE_t = \; & a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1} \\ & - \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1}) \end{aligned} \tag{100.1}$$

where,

| | | |
|---|---|---|
| LCRUDE | = | natural log of crude oil production |
| LOILRES | = | natural log of beginning of year oil reserves |
| LPOIL | = | natural log of the regional wellhead price of oil in 1987 dollars |
| $\rho$ | = | 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 |
| ρ | .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 |
| ρ | .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:

$$\begin{aligned}LCRUDE_t = {} & a0 + a1*LOILRES_t + a2*LPOIL_t + a3*LPDUM3_t + a4*LPDUM \\ & a5*LPDUM5_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} + \\ & a2*LPOIL_{t-1} + a3*LPDUM3_{t-1} + a4*LPDUM4_{t-1} + a5*LPDUM\end{aligned} \qquad (100.2)$$

where,

| | | |
|---|---|---|
| LPDUMr | = | DUMr*LPOIL |
| DUMr | = | a dummy variable that equals 1 if region=r and 0 otherwise |
| r | = | onshore regions 2 through 5 |
| ρ | = | 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 |
| ρ | .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 LPDUMr to the coefficient on LPOIL.

### *Lower 48 Dry Non-Associated Natural Gas*

The data for onshore regions 1 through 6 were pooled and a single regression equation estimated with dummy variables used to allow the slope coefficients to vary across regions. Region 1 was taken as the base region. The equation was estimated using the non-linear two stage least squares procedure in TSP. The form of the equation is given by:

$$\begin{aligned} LPROD = {} & A0 + (A1 + \sum_r Ar * DUMr) * LGASRES + (B1 + \sum_r Br * DUMr) * \\ & LPGAS + C * DEDSHR \end{aligned} \qquad (100.3)$$

where,

| | | |
|---|---|---|
| LPROD | = | natural log of natural gas production |
| LGASRES | = | natural log of beginning of year natural gas reserves |
| LPGAS | = | natural log of the regional wellhead price of natural gas in 1987 dollars |
| DEDSHR | = | natural log of the share of natural gas production that is accounted for by pipeline sales(included to capture the effect of open access on production) |
| DUMr | = | dummy variable that equals 1 if region = r and 0 otherwise |
| r | = | onshore regions 2 through 6. |

**Results**

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| A0 | -3.02039 | 3.46358 | -.872044 |
| A1 | .962078 | .206360 | 4.66213 |
| A2 | .067699 | .016754 | 4.04076 |
| A3 | .049399 | .017549 | 2.81494 |
| A4 | .062093 | .018170 | 3.41733 |
| A5 | .450603E-02 | .016987 | .265262 |
| A6 | .047330 | .054670 | .865738 |
| B1 | .852276 | .326959 | 2.60668 |
| B2 | -.589608 | .331977 | -1.77605 |
| B3 | -.645398 | .306376 | -2.10623 |
| B4 | -.730398 | .341712 | -2.13747 |
| B5 | -.733917 | .265693 | -2.76228 |
| B6 | -.388545 | .471104 | -.822833 |
| C | -.305243 | .082627 | -3.69421 |

SAMPLE: 1985 to 1990
NUMBER OF OBSERVATIONS = 36

Dependent variable: LPROD

Mean of dependent variable = 13.7972
Std. dev. of dependent var. = 1.08967
Sum of squared residuals = .089311
Variance of residuals = .405960E-02
Std. error of regression = .063715
R-squared = .997851
Adjusted R-squared = .996581
Durbin-Watson statistic = 2.42140

The price elasticity of natural gas production for onshore region 1 is given by the estimated parameter B1. The price elasticity for any other onshore region r (r = 2 through 6) is derived by adding the estimate for Br to the value of B1.

### *Offshore Gulf of Mexico Crude Oil*

Price elasticities were estimated using OLS. The functional form is given by:

$$LCRUDE = a0 + a1*LOILRES + a2*LPOIL + a3*LCRUDE(-1) + a4*DUM \qquad (100.4)$$

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:

$$LCRUDE_t = a0 + a1*LOILRES_t + a2*LPOIL_t + \rho*LCRUDE_{t-1} - \rho*(a0 + a1*LOILRES_{t-1} + a2*LPOIL_{t-1}) \quad (100.5)$$

where,

| | | |
|---|---|---|
| LCRUDE | = | natural log of crude oil production |
| LOILRES | = | natural log of beginning of year crude oil reserves |
| LPOIL | = | natural log of the regional wellhead price of crude oil in 1987 dollars |
| ρ | = | autocorrelation parameter |
| t | = | year. |

**Results**

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| a0 | 1.34325 | .443323 | 3.02995 |
| LOILRES | .310216 | .067090 | 4.62390 |
| LPOIL | .181190 | .067391 | 2.68865 |
| ρ | -.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 |

## Option 2

### *Natural Gas*

The following variables are the instrumental variables not included in the estimation of the supply curve (Option 1):

| | |
|---|---|
| TRAN_M: | the differential between the average citygate price and the average wellhead price |
| L_PR(-1): | the lag of the dependent variable |
| KERN_R: | a dummy variable for the Kern river pipeline project which increased the demand for gas (at the wellhead) in the Rocky Mountain region. Equal to one after 1992 in OGSM region 5. |
| KERN_R(-1): | the lag of the Kern river dummy variable. |
| LNPGAS(-1): | lag of the natural log of the wellhead price. |
| NEWTREND: | time trend reflecting the growth in demand after 1990 due to the 1990 Clean Air Act. |
| CARRIAGE(-1): | Lag of Carriage |
| REAL_GDP: | real GDP |
| HDD_TOT: | total HDD in the year. |
| WINTER: | HDD in the heating season relative to the total |
| NUM_CUST: | number of residences that use gas |
| WOP: | world oil price |

Dependent variable: L_PR
Number of observations: 153
Sample period: 1987-1995

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = -1.55656 | Mean of dependent variable = -2.38198 |
| Std. dev. of dependent var. = .339730 | Std. dev. of dependent var. = .478945 |
| Sum of squared residuals = 4.94292 | Sum of squared residuals = 4.94292 |
| Variance of residuals = .036887 | Variance of residuals = .036887 |
| Std. error of regression = .192061 | Std. error of regression = .192061 |
| R-squared = .718249 | R-squared = .858237 |
| Adjusted R-squared = .680402 | Adjusted R-squared = .839194 |
| Durbin-Watson statistic = 1.76858 | Durbin-Watson statistic = 1.76858 |
| Rho (autocorrelation coef.) = .344682 | |
| Standard error of rho = .075891 | |
| t-statistic for rho = 4.54180 | |
| Log of likelihood function = 45.4873 | |

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| NGTDM2 | -3.20969 | .267598 | -11.9944 |
| NGTDM3 | -2.93531 | .270587 | -10.8479 |
| NGTDM4 | -3.35590 | .227408 | -14.7571 |
| NGTDM5 | -3.69366 | .233568 | -15.8141 |
| NGTDM6 | -3.43275 | .283371 | -12.1140 |
| NGTDM7 | -3.34650 | .254599 | -13.1442 |

| | | | |
|---|---|---|---|
| NGTDM8 | -2.86265 | .254779 | -11.2358 |
| NGTDM9 | -2.42438 | .236553 | -10.2488 |
| NGTDM10 | -2.66263 | .236034 | -11.2807 |
| NGTDM11 | -2.73809 | .234900 | -11.6564 |
| NGTDM12 | -3.41090 | .225810 | -15.1052 |
| NGTDM13 | -3.09228 | .223031 | -13.8648 |
| NGTDM15 | -2.41018 | .230816 | -10.4420 |
| NGTDM16 | -3.63902 | .229486 | -15.8572 |
| NGTDM17 | -2.63371 | .253934 | -10.3716 |
| NGTDM19 | -2.28560 | .244244 | -9.35786 |
| NGTDM20 | -3.30895 | .271987 | -12.1658 |
| CARRIAGE | .619146 | .222396 | 2.78398 |
| LNPGAS | .281044 | .128351 | 2.18965 |

***Crude Oil***

Dependent variable: L_PR
Number of observations: 96

(Statistics based on transformed data)
Mean of dependent variable = -.584480
Std. dev. of dependent var. = .261828
Sum of squared residuals = .437095
Variance of residuals = .508250E-02
Std. error of regression = .071292
R-squared = .936387
Adjusted R-squared = .929730
Durbin-Watson statistic = 1.44267
Rho (autocorrelation coef.) = .761773
Standard error of rho = .069740
t-statistic for rho = 10.9230
F-statistic (zero slopes) = 132.820
Log of likelihood function = 119.123
(Statistics based on original data)
Mean of dependent variable = -2.14110
Std. dev. of dependent var. = .431497
Sum of squared residuals = .474641
Variance of residuals = .551908E-02
Std. error of regression = .074290
R-squared = .973561
Adjusted R-squared = .970794
Durbin-Watson statistic = 1.40316

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| REG1 | -2.04097 | .077337 | -26.3907 |
| REG2 | -1.85617 | .077354 | -23.9959 |
| REG3 | -1.87340 | .077245 | -24.2528 |
| REG4 | -2.43427 | .077277 | -31.5004 |
| REG5 | -2.11561 | .076618 | -27.6126 |

| | | | |
|---|---|---|---|
| REG6 | -2.53210 | .074498 | -33.9888 |
| PACIFIC | -2.49487 | .084604 | -29.4887 |
| GULF_MEX | -1.80544 | .077760 | -23.2180 |
| POIL | .405730E-02 | .172851E-02 | 2.34728 |
| PAC_DUM | -.593325 | .071096 | -8.34536 |

## Option 3

### *Natural Gas*

Option 3 version of the model employs the same list of excluded instrumental variable as does Option 1. In the case of the Gulf of Mexico, a preliminary analysis indicated that reserve additions had no statistically significant impact on the production to reserves ratio. Accordingly, this variable was dropped from the equation. The results are presented below.

Dependent variable: L_PR Number of observations: 153

| (Statistics based on transformed data) | (Statistics based on original data) |
|---|---|
| Mean of dependent variable = -1.42246 | Mean of dependent variable = -2.38198 |
| Std. dev. of dependent var. = .319648 | Std. dev. of dependent var. = .478945 |
| Sum of squared residuals = 4.46210 | Sum of squared residuals = 4.46210 |
| Variance of residuals = .033804 | Variance of residuals = .033804 |
| Std. error of regression = .183858 | Std. error of regression = .183858 |
| R-squared = .712709 | R-squared = .872026 |
| Adjusted R-squared = .669180 | Adjusted R-squared = .852636 |
| Durbin-Watson statistic = 1.62494 | Durbin-Watson statistic = 1.62494 |
| Rho (autocorrelation coef.) = .400681 | |
| Standard error of rho = .074072 | |
| t-statistic for rho = 5.40936 | |
| Log of likelihood function = 53.3160 | |

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| NGTDM2 | -3.11539 | .278833 | -11.1730 |
| NGTDM3 | -2.79435 | .282534 | -9.89030 |
| NGTDM4 | -3.26363 | .241656 | -13.5052 |
| NGTDM5 | -3.59802 | .246935 | -14.5708 |
| NGTDM6 | -3.31451 | .293341 | -11.2992 |
| NGTDM7 | -3.25806 | .266375 | -12.2311 |
| NGTDM8 | -2.75296 | .266779 | -10.3193 |
| NGTDM9 | -2.30780 | .250683 | -9.20604 |
| NGTDM10 | -2.55775 | .249785 | -10.2398 |
| NGTDM11 | -2.64004 | .248712 | -10.6148 |
| NGTDM12 | -3.30683 | .239582 | -13.8025 |
| NGTDM13 | -2.98086 | .237457 | -12.5533 |
| NGTDM15 | -2.29135 | .245011 | -9.35203 |
| NGTDM16 | -3.51849 | .243483 | -14.4506 |
| NGTDM17 | -2.54880 | .265098 | -9.61458 |
| NGTDM19 | -2.21204 | .256088 | -8.63780 |
| NGTDM20 | -3.23998 | .281333 | -11.5165 |

| | | | |
|---|---|---|---|
| CARRIAGE | .536012 | .237033 | 2.26134 |
| LNPGAS | .282299 | .123910 | 2.27826 |
| RA_ON(-1) | -.346953 | .100072 | -3.46705 |
| RA_PAC(-1) | -1.32524 | .529135 | -2.50454 |

### *Crude Oil*

Dependent variable: L_PR
Number of observations: 96

(Statistics based on transformed data)
Mean of dependent variable = -.632077
Std. dev. of dependent var. = .266610
Sum of squared residuals = .324944
Variance of residuals = .391498E-02
Std. error of regression = .062570
R-squared = .956140
Adjusted R-squared = .949799
Durbin-Watson statistic = 1.74406
Rho (autocorrelation coef.) = .739711
Standard error of rho = .074223
t-statistic for rho = 9.96602
F-statistic (zero slopes) = 136.820
Log of likelihood function = 133.659
(Statistics based on original data)
Mean of dependent variable = -2.14110
Std. dev. of dependent var. = .431497
Sum of squared residuals = .366427
Variance of residuals = .441479E-02
Std. error of regression = .066444
R-squared = .979550
Adjusted R-squared = .976594
Durbin-Watson statistic = 1.65740

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| REG1 | -2.01983 | .065639 | -30.7717 |
| REG2 | -1.83432 | .065673 | -27.9311 |
| REG3 | -1.85302 | .065588 | -28.2523 |
| REG4 | -2.42216 | .064756 | -37.4044 |
| REG5 | -2.09453 | .065178 | -32.1357 |
| REG6 | -2.52458 | .061903 | -40.7830 |
| PACIFIC | -2.42401 | .073212 | -33.1095 |
| GULF_MEX | -1.64851 | .080708 | -20.4256 |
| POIL | .415848E-02 | .151184E-02 | 2.75061 |
| RA_ON(-1) | -.200143 | .121602 | -1.64589 |
| RA_PAC(-1) | 1.12904 | .280958 | 4.01853 |
| RA_GOM(-1) | -.974495 | .299639 | -3.25223 |
| PAC_DUM | -.784702 | .076707 | -10.2298 |

## Associated Dissolved Gas Equations

Associated dissolved gas production was hypothesized to be a function of crude oil production. The form of the equation was assumed to be log-linear. The equations were estimated in log-linear form using ordinary least squares (OLS) technique available in TSP. The forms of the equations are :

$$LADGAS_{r,t} = \ln(\alpha 0)_r + \ln(\alpha 1)_r * DUM86_t + (\beta 0_r + \beta 1_r * DUM86_t) * LOILPROD_{r,t} \quad (106)$$

**Results**

```
                           Onshore Region   1
                           *****************

              Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  11 to 24
Number of observations:  14

 Mean of dependent variable = 5.12499
Std. dev. of dependent var. = .164729
   Sum of squared residuals = .038353
      Variance of residuals = .319609E-02
   Std. error of regression = .056534
                  R-squared = .891278
         Adjusted R-squared = .882218
    Durbin-Watson statistic = 1.75215
  F-statistic (zero slopes) = 98.3730
 Schwarz Bayes. Info. Crit. = -5.52297
 Log of likelihood function = 21.4347

           Estimated    Standard
Variable  Coefficient     Error       t-statistic
ln(α0)    2.07491       .307892       6.73908
β0        .701885       .070766       9.91832

                  OBS        REGION          YEAR
11           11.00000       1.00000    1980.00000
24           24.00000       1.00000    1993.00000


                           Onshore Region   2
                           *****************

              Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  35 to 48
Number of observations:  14

 Mean of dependent variable = 6.49697
Std. dev. of dependent var. = .266043
   Sum of squared residuals = .048056
      Variance of residuals = .400467E-02
   Std. error of regression = .063282
                  R-squared = .947773
         Adjusted R-squared = .943420
    Durbin-Watson statistic = 1.22587
  F-statistic (zero slopes) = 217.764
```

```
 Schwarz Bayes. Info. Crit. = -5.29744
 Log of likelihood function = 19.8560


           Estimated    Standard
Variable  Coefficient     Error       t-statistic
ln(α0)    -3.07832      .649092       -4.74250
β0        1.56944       .106353       14.7568

                   OBS        REGION          YEAR
35            35.00000       2.00000    1980.00000
48            48.00000       2.00000    1993.00000
```

Onshore Region 3
*****************

Method of estimation = Ordinary Least Squares

```
Dependent variable: LADGAS
Current sample:  65 to 72
Number of observations:  8

 Mean of dependent variable = 5.92117
Std. dev. of dependent var. = .188982
   Sum of squared residuals = .013619
      Variance of residuals = .226982E-02
   Std. error of regression = .047643
                  R-squared = .945524
         Adjusted R-squared = .936445
    Durbin-Watson statistic = 2.19391
  F-statistic (zero slopes) = 104.141
 Schwarz Bayes. Info. Crit. = -5.85588
 Log of likelihood function = 14.1514

           Estimated    Standard
Variable  Coefficient     Error       t-statistic
ln(α0)    -1.65468      .742561       -2.22834
β0        1.42210       .139354       10.2050

                   OBS        REGION          YEAR
65            65.00000       3.00000    1986.00000
72            72.00000       3.00000    1993.00000
```

Onshore Region 4
*****************

Method of estimation = Ordinary Least Squares

```
Dependent variable: LADGAS
Current sample:  82 to 96
Number of observations:  15

 Mean of dependent variable = 6.51049
Std. dev. of dependent var. = .080768
   Sum of squared residuals = .065307
      Variance of residuals = .502359E-02
   Std. error of regression = .070877
                  R-squared = .284921
         Adjusted R-squared = .229915
```

```
   Durbin-Watson statistic = 1.28517
  F-statistic (zero slopes) = 5.17980
 Schwarz Bayes. Info. Crit. = -5.07564
 Log of likelihood function = 19.4913

           Estimated    Standard
Variable  Coefficient     Error       t-statistic
ln(α0)    4.49271       .886765       5.06640
β0        .315372       .138569       2.27592

                  OBS        REGION          YEAR
82           82.00000       4.00000    1979.00000
96           96.00000       4.00000    1993.00000
```

Onshore Region 5
*****************

```
            Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  107 to 120
Number of observations:  14

 Mean of dependent variable = 5.49207
Std. dev. of dependent var. = .176267
   Sum of squared residuals = .169883
      Variance of residuals = .014157
   Std. error of regression = .118983
                  R-squared = .579402
         Adjusted R-squared = .544352
    Durbin-Watson statistic = 1.15658
  F-statistic (zero slopes) = 16.5308
 Schwarz Bayes. Info. Crit. = -4.03469
 Log of likelihood function = 11.0168

           Estimated    Standard
Variable  Coefficient     Error       t-statistic
ln(α0)    5.34284       .048562       110.021
β1        .047917       .011785       4.06581

                  OBS        REGION          YEAR
107         107.00000       5.00000    1980.00000
120         120.00000       5.00000    1993.00000
```

Onshore Region 6
*****************

```
            Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample:  131 to 144
Number of observations:  14

 Mean of dependent variable = 5.20320
Std. dev. of dependent var. = .126146
   Sum of squared residuals = .030218
      Variance of residuals = .302183E-02
   Std. error of regression = .054971
                  R-squared = .853924
```

Adjusted R-squared = .810102
Durbin-Watson statistic = 1.16621
F-statistic (zero slopes) = 19.4859
Schwarz Bayes. Info. Crit. = -5.38435
Log of likelihood function = 23.1034

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| ln($\alpha$0) | -12.1971 | 2.95896 | -4.12210 |
| ln($\alpha$1) | 10.7230 | 3.27845 | 3.27075 |
| $\beta$0 | 2.99621 | .508887 | 5.88778 |
| $\beta$1 | -1.83291 | .565439 | -3.24157 |

| | OBS | REGION | YEAR |
|---|---|---|---|
| 131 | 131.00000 | 6.00000 | 1980.00000 |
| 144 | 144.00000 | 6.00000 | 1993.00000 |

## Offshore California

Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample: 146 to 157
Number of observations: 12

Mean of dependent variable = 3.46459
Std. dev. of dependent var. = .235388
Sum of squared residuals = .130029
Variance of residuals = .016254
Std. error of regression = .127490
R-squared = .786657
Adjusted R-squared = .706654
Durbin-Watson statistic = 1.46033
F-statistic (zero slopes) = 9.83279
Schwarz Bayes. Info. Crit. = -3.69661
Log of likelihood function = 10.1222

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| ln($\alpha$0) | -42.1148 | 14.1531 | -2.97566 |
| ln($\alpha$1) | 43.1508 | 14.3122 | 3.01497 |
| $\beta$0 | 10.7112 | 3.34207 | 3.20497 |
| $\beta$1 | -10.0929 | 3.38203 | -2.98428 |

| | OBS | REGION | YEAR |
|---|---|---|---|
| 146 | 146.00000 | 7.00000 | 1982.00000 |
| 157 | 157.00000 | 7.00000 | 1993.00000 |

## Offshore Gulf of Mexico

Method of estimation = Ordinary Least Squares

Dependent variable: LADGAS
Current sample: 159 to 170
Number of observations: 12

Mean of dependent variable = 6.38670

```
Std. dev. of dependent var. = .092892
   Sum of squared residuals = .026872
      Variance of residuals = .298574E-02
   Std. error of regression = .054642
                  R-squared = .721601
         Adjusted R-squared = .659735
    Durbin-Watson statistic = 2.45155
  F-statistic (zero slopes) = 11.3951
 Schwarz Bayes. Info. Crit. = -5.48036
 Log of likelihood function = 19.5823
```

| Variable | Estimated Coefficient | Standard Error | t-statistic |
|---|---|---|---|
| ln(α1) | 4.21386 | 1.49771 | 2.81354 |
| β0 | 1.07834 | .466028E-02 | 231.391 |
| β1 | -.697473 | .258646 | -2.69663 |

| | OBS | REGION | YEAR |
|---|---|---|---|
| 159 | 159.00000 | 8.00000 | 1982.00000 |
| 170 | 170.00000 | 8.00000 | 1993.00000 |

## Canadian Successful Oil and Gas Wells Equations

A successful oil wells equation and a successful gas wells equation were estimated in generalized difference form using SURE. Successful oil (gas) wells were estimated as a function of the expected DCF for an oil (gas) well and a dummy variable to control for Canadian oil and gas policy changes in the early to mid 1980's.

$$\begin{aligned} WELLS_{k,t} &= \beta0_k + \beta1_k * DCF_{k,t} + \beta2_k * DUM83_t + \rho_t * WELLS_{k,t-1} \\ &- \rho_k * (\beta0_k + \beta1_k * DCF_{k,t-1} + \beta2_k * DUM83_{t-1}) \end{aligned} \quad (131)$$

where,

| | | |
|---|---|---|
| WELLS | = | successful Canadian well completions |
| DCF | = | discounted cash flow for a well |
| DUM83 | = | 1 if t >1982, 0 otherwise |
| β0, β1, β2 | = | econometrically estimated parameters |
| ρ | = | autocorrelation parameter |
| k | = | fuel type |
| t | = | year. |

**Results**

| Parameter | OIL | GAS |
|---|---|---|
| $\beta 0$ | 499.230<br>(1.33979) | 1829.02<br>(2.94956) |
| $\beta 1$ | 0.170973E-02<br>(4.18866) | 0.132393E-02<br>(3.23435) |
| $\beta 2$ | 949.572<br>(2.05196) | -1276.28<br>(-3.06764) |
| $\rho$ | 0.298608<br>(1.41467) | 0.726749<br>(4.50509) |

NUMBER OF OBSERVATIONS = 20

Standard Errors computed from quadratic form of analytic first derivatives (Gauss)

Dependent variable: WELLS (oil)

| | | |
|---|---|---|
| Mean of dependent variable | = | 2235.30 |
| Std. dev. of dependent var. | = | 1467.19 |
| Sum of squared residuals | = | .976854E+07 |
| Variance of residuals | = | 488427. |
| Std. error of regression | = | 698.876 |
| R-squared | = | .764132 |
| Durbin-Watson statistic | = | 2.10944 |

Dependent variable: WELLS (gas)

| | | |
|---|---|---|
| Mean of dependent variable | = | 2353.75 |
| Std. dev. of dependent var. | = | 958.064 |
| Sum of squared residuals | = | .391239E+07 |
| Variance of residuals | = | 195619. |
| Std. error of regression | = | 442.289 |
| R-squared | = | .789470 |
| Durbin-Watson statistic | = | 1.95590 |