OCS Study
MMS 2004-009

Coastal Marine Institute

Long-Term Oil and Gas Structure Installation and Removal Forecasting in the Gulf of Mexico: A Decision- and Resource-Based Approach

U.S. Department of the Interior
Minerals Management Service
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May 2004

Prepared under MMS Contract
1435-01-99-CA-30951-17806
by
The Center for Energy Studies
Louisiana State University
Baton Rouge, Louisiana 70803

Published by

U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

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CITATION

Suggested citation:

Kaiser, M.J., D.V. Mesyanzhinov, and A.G. Pulsipher. 2004. Long-term oil and gas structure installation and removal forecasting in the Gulf of Mexico: A decision- and resource-based approach. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, La. OCS Study MMS 2004-009. 56 pp.

ACKNOWLEDGMENTS

The advice, assistance, and helpful criticisms of Richard Desselles and Thierry DeCort of the MMS are gratefully acknowledged. The remarks of an anonymous reviewer are also appreciated. This paper was prepared on behalf of the U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region. The opinions, findings, conclusions, or recommendations expressed in this paper are those of the authors, and do not necessarily reflect the views of the Minerals Management Service. Funding for this research was provided through the U.S. Department of the Interior and the Coastal Marine Institute, Louisiana State University.

ABSTRACT

The platform forecasting procedures employed by the Resource Evaluation Analysis (REA) Unit of the U.S. Minerals Management Service (MMS) is evaluated and quantified in a formal analytic framework. The assumptions employed in the REA/MMS methodology, the uncertainty associated with the modeling procedures, and the primary consequences of the assumption set are examined. Ten recommendations are suggested to clarify and maintain the consistency of the approach, and an alternative model is described which incorporates the suggestions for improvement. The analytic framework of the alternative model is presented and compared to the REA/MMS procedure.

A long-term infrastructure forecast in the Gulf of Mexico is developed in a disaggregated decision- and resource-based environment. Models for the installation and removal rates of structures are performed across five water depth categories for the Western and Central Gulf of Mexico planning areas for structures grouped according to a major and nonmajor classification. Master hydrocarbon production schedules are constructed per water depth and planning area using a two-parameter decision model, where “bundled” resources are recoverable at a given time and at a specific rate. The infrastructure requirements to support the expected production are determined by extrapolating historical data. The analytic forecasting framework allows for subjective judgment, technological change, analogy, and historical trends to be employed in a user-defined manner. Special attention to the aggregation procedures employed and the general methodological framework are highlighted, including a candid discussion of the limitations of analysis and suggestions for further research.

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CHAPTER 1: AN ASSESSMENT OF THE INFRASTRUCTURE FORECAST METHODOLOGY OF THE U.S. MINERALS MANAGEMENT SERVICE

1.1. Introduction

The Resource and Economic Analysis (REA) Unit of the U.S. Minerals Management Service (MMS) performs infrastructure forecasting in support of economic and environmental impact studies in the Gulf of Mexico (GOM) (Coffman *et al*., 2001). The MMS performs a number of forecasts related to GOM infrastructure, including but not necessarily limited to,

Number of exploratory wells,
Number of delineation wells,
Number of development wells,
Number of production wells,
Number of workovers,
Number of structures installed,
Number of structures removed,
Number of subsea completions, and
Miles pipeline.

Infrastructure forecast is an important input element to decision making at the MMS, and because of the scale of activities involved, drilling activity and structure installations are closely watched and used as a general guide on resource levels and development expectations.

The purpose of exploration is to discover the presence of oil and gas, and the number of exploratory wells provides a gauge of interest in the region and the level of development activity expected in the future. If hydrocarbons are discovered, delineation wells may be drilled to establish the amount of recoverable oil, production mechanism, and structure type. The number of wells required to develop reserves depends on a trade-off between risked capital and expected production. Development wells are drilled to produce the hydrocarbon resources discovered, and production wells are defined (aptly enough) as those wells that are currently in production. Development and production wells are tied into structures such as caissons, well protectors, and both fixed and floating platforms. If the wellhead control values (Christmas tree, Blow Out Preventer, etc.) are located on the seabed, the well is referred to as a subsea completion. Workovers are carried out periodically to ensure the continued productivity of the wells. The number of structures installed is an important statistic since platforms support production, must be manufactured prior to development, installed, serviced during production, and finally removed after decommissioning. The economic, environmental, and socioeconomic impact of structure installations is a significant contribution to the economic vitality of Gulf Coast communities and is evaluated and assessed with every five year lease program on offer.

Infrastructure forecasting is an uncertain and difficult endeavor due to the confluence of a number of interrelated factors, such as the uncertainty of the resource base and its future development; the uncertain economic and regulatory environment; and the large number of operator- and site-specific variables that drive activity trends. To help minimize the forecast uncertainty and ensure the accuracy and reliability of input-output models, it is important to maintain forecasting procedures that are well documented and established on a solid quantitative foundation.

There is only a limited amount of documentation supporting the REA/MMS forecast models, however, and so the first task of this paper is to formalize the REA/MMS procedure in a quantitative framework. The REA's platform forecasting procedure is analyzed in an effort to add operational insight into the methodology and to provide support for refinements to the approach. The primary purpose of this paper is thus three-fold:

(1) To document and specify the procedures currently employed by the REA in the construction of a platform forecast in the Gulf of Mexico,
(2) To analyze the assumption set employed in the REA forecast and to critique the procedure, and
(3) To use the assessment as a guide to develop an alternative methodology for platform forecasting.

The outline of Chapter 1 is as follows. In Chapter 1.2, a description of the REA/MMS platform forecast procedure is detailed. The general methodology is presented in Chapter 1.2.1 followed by important background information in Chapter 1.2.2 on the definition of resource categories. The production profile forecast is described in Chapter 1.2.3 and the infrastructure requirements forecast is described in Chapter 1.2.4. A critique of the REA methodology is discussed in Chapter 1.3 and a series of procedural recommendations are presented in Chapter 1.4. In Chapter 1.5, the analytic framework for an alternative infrastructure forecast is presented. The methodology is outlined in Chapter 1.5.1, followed in Chapter 1.5.2 and Chapter 1.5.3 by a description of the cumulative production profile and the derivation for the expression of the number of active platforms. The alternative approach is formalized in Chapter 1.5.4 and compared to the REA approach in Chapter 1.5.5. Conclusions are presented in Chapter 1.6.

1.2. The MMS Infrastructure Forecast Methodology

<u>1.2.1. The REA/MMS Infrastructure Forecasting Procedure:</u> Platform forecasting was initiated at the REA/MMS in the early 1990's and has evolved to a sophisticated "resource-based" methodology. The infrastructure forecast employed at the REA/MMS is summarized as a four-step procedure (Desselles, 2001a):

Step 1. Hydrocarbon production profiles per planning area are constructed over a 40-year time horizon.

Step 2. Annual production per active platform is forecast per water depth and planning area category.

Step 3. The number of active platforms required to meet the annual production projections (from *Step 1*) is determined using the annual production to active platform ratio forecast (from *Step 2*).

Step 4. Platform installation and removal rates are estimated to achieve the number of active platforms computed in *Step 3*.

The hydrocarbon production profile outlined in *Step 1* will be discussed Chapter 1.2.3 after the resource categories are defined. The infrastructure forecast outlined in *Steps 2-4* will be examined in Chapter 1.2.4.

1.2.2. Resource Category Definition: The MMS is required by legislative mandate to provide assessments of Outer Continental Shelf (OCS) undiscovered oil and gas. Reserve estimates are performed frequently – normally every year or so – while undiscovered oil and gas assessments are performed every four years or so.

Reserves are those quantities of hydrocarbon that are anticipated to be commercially recoverable from known accumulations. Proved reserves can be thought of as inventory in the ground already paid for with investment dollars. The inventory is known with high confidence ("reasonable certainty") and is specified in terms of a given reserves amount. Proved reserves are known with reasonable certainty because the field has been defined by appraisal wells, and while developed reserves can be produced from existing wells and existing infrastructure, undeveloped reserves will have to be produced from wells that have not yet been drilled or from existing wells that are "beyond the pipe." Proved reserves are *not* fixed, but rather, depend upon the amount of exploration undertaken, technology, and economic conditions, and thus can vary as a result of changes in the external position of these factors; e.g., proved reserves increase with successful exploration and decrease by the amount of production.

Unproven reserves are calculated similar to proven reserves, but because of technical, contractual, economic, or regulatory uncertainty, their production is not as certain as proven reserves. Unproven reserves are producible and economically recoverable, but their presence is based more on geologic interpretation than on physical evidence, and hence, the quantities are less certain than proved reserves.

Reserves appreciation refers to the *expected* increase in estimates of proven reserves as a consequence of the extension of known pools or discovery of new pools within existing fields. Reserves appreciation, or reserves growth, represents the expected increase in the estimates of original proved reserves of an oil and gas field. Field growth can result from several factors such as improvements in recovery, physical expansion of the field, better understanding of the reservoir, data re-evaluation, extension drilling, and changes in economic parameters. Changes in reserve estimates may be negative as well as positive, but on average reserve estimates have grown over time. Field growth is most rapid the first few years after a field is discovered, and later tend to level out at a smaller increment.

Statistical growth curves based on historic data are commonly used to estimate reserves appreciation, and this is the method employed by the MMS (Lore *et al*., 2001).

Unproved reserves and reserves appreciation are not quite the same as proved reserves because for unproved reserves and appreciation we are forecasting how to build inventory, and of course, we don't know the required investment or the future prices that will induce such investment. Hence, unproved reserves and reserves appreciation are more uncertain than remaining proved reserves, but are generally considered reliable and more certain than undiscovered resources.

Undiscovered conventionally recoverable resources (or, ultimately recoverable reserves) is oil and gas which has not yet been physically discovered but for which there is "some certainty" that it exists and can be extracted with, by definition, conventional technology[1]. Undiscovered resources are those resources outside of known fields that is postulated to exist based on broad geologic knowledge. Undiscovered resources come in two forms – conventionally recoverable and economically recoverable. Conventionally recoverable resources are that portion of the hydrocarbon potential that is producible, using present or reasonably foreseeable technology, without any consideration of economic feasibility. Undiscovered conventionally recoverable resources (UCRR) are primary located outside of known fields, but undiscovered pools within known fields are also included to the extent that they occur within separate plays. The portion of UCRR that is economically recoverable under imposed economic and technologic conditions[2] is referred to as undiscovered economically recoverable resources (UERR). Resource appraisals are based on group assessments and the application of subjective probability estimates of various parameters. Undiscovered resources have significant uncertainty associated with its expected magnitude and development.

The following notation is established. Proved reserves located within the Western and Central GOM planning area P_i, i=1,2, are denoted by $R_1(P_i)$, unproved reserves by $R_2(P_i)$, reserves appreciation by $R_3(P_i)$, undiscovered conventionally recoverable resources by $R_4(P_i)$, and undiscovered economically recoverable resources by $R_5(P_i)$. The magnitude of $\{R_1(P_i),\ R_2(P_i),\ R_3(P_i),\ R_4(P_i),\ R_5(P_i)\}$ depend upon a number of uncertain economic, geologic, and technologic parameters, and are considered stochastic quantities; e.g., although the estimate of the magnitude of $R_1(P_i)$ is fairly certain, $R_5(P_i)$ is highly variable, and the uncertainty associated with $R_2(P_i)$, $R_3(P_i)$, and $R_4(P_i)$ fall in

[1] While unconventional oil deposits (e.g., tar sand, oil shale) have thus far contributed little to domestic U.S. production, unconventional natural gas deposits from low-permeability sandstones, fractured shale, and coal beds are making an important contribution, and so undiscovered conventionally recoverable resources may be underestimated. The distinction between "conventional" and "unconventional" resources remains a bit fuzzy and should be viewed somewhat skeptically.

[2] The imposed economic scenario is defined to be a 12.5-percent or 16.7 percent royalty rate, 35 percent Federal tax rate, three percent inflation rate, and natural gas prices related to oil prices at 66 percent of the oil-energy equivalent (Lore *et al*., 2001).

between these two classifications. Resource estimates based on the 2000 National Assessment data are depicted in Table A.1[3].

The elements $\{R_1(P_i),\ R_2(P_i),\ R_3(P_i)\}$ are assessed as point estimates in the 2000 National Assessment and represent average (or expected) values, while $\{R_4(P_i),\ R_5(P_i)\}$ are estimated relative to a "low" (pessimistic) and "high" (optimistic) case scenario corresponding to a "pessimistic" and "optimistic" economic environment[4]. For $R_4(P_i)$, the low and high estimates are referred to as F5 (5th percentile) and F95 (95th percentile), respectively, while the average estimate is referred to as F50 (50th percentile). The F5 estimate reflects the resource quantity having a five percent probability that the ultimate resource, when found, will equal or exceed the estimated quantity. The F50 and F95 estimates have similar interpretations. For $R_5(P_i)$, the low and high estimates represent the mean resources at \$18/bbl oil, \$2.11/Mcf and \$30/bbl oil, \$3.52/Mcf.

1.2.3. The Production Profile Forecast: The Resource and Economic Analysis Unit of the MMS performs a 40-year production profile forecast for oil and natural gas for each planning area of the Gulf of Mexico. The REA constructs production profiles by specifying annual production rates to recover the resource base within each resource category over the time horizon of the forecast. If

$q_{(o,g)}^{[L,H]}(P_i,t,K_i) =$ Annual production rate of (oil, gas) = (o, g) under a [low, high] = [L, H] case economic scenario corresponding to planning area P_i at time t and resource category K_i,

then the construction of the supply curve follows by specifying $q_{(o,g)}^{[L,H]}(P_i,t,K_i)$ each year over the range (τ, τ+40] subject to the following conditions:

$$\sum_{t=\tau}^{\tau+40} q_{(o,g)}^{[L,H]}(P_i,t,K_1) = p_1^{[L,H]}K_1,$$

$$\sum_{t=\tau}^{\tau+40} q_{(o,g)}^{[L,H]}(P_i,t,K_2) = p_2^{[L,H]}K_2, \qquad (1)$$

where τ represents the current time; $K_1 = \{R_1(P_i) + R_2(P_i) + R_3(P_i)\}$; $K_2 = \{R_5(P_i)\}$; and $0 < p_i^{[L,H]} \le 1$, i=1,2. Resource category K_1 is reserves and appreciation while K_2 is undiscovered resources. If $p_i^{[L,H]} = 1$, full recovery of the resource category is specified, while $p_i^{[L,H]} < 1$ indicates only partial recovery. The value of $p_i^{[L,H]}$ can be viewed as a

[3] The Eastern GOM planning area is not considered due to its low production and activity levels and historic restrictions on leasing sales.

[4] The pessimistic economic scenario corresponds to \$18/bbl oil and \$2.11/Mcf gas, while the optimistic economic scenario corresponds to \$30/bbl oil and \$3.52/Mcf gas.

decision variable, and in the present context is inferred from the production profiles established by the REA.

After the production profiles

$$q_{(o,g)}^{[L,H]}(P_i,t,K_j)\,,\ i=1,2;\ j=1,2,$$

are constructed for each resource class K_j, the total hydrocarbon annual production within planning area P_i at time t, $q_{(o,g)}^{[L,H]}(P_i,t)$, is computed as the sum across the two resource categories; i.e.,

$$q_{(o,g)}^{[L,H]}(P_i,t) = q_{(o,g)}^{[L,H]}(P_i,t,K_1) + q_{(o,g)}^{[L,H]}(P_i,t,K_2)\,, \tag{2}$$

while the cumulative production at time $t = x$ is defined as

$$Q_{(o,g)}^{[L,H]}(P_i,x) = \sum_{t=\tau}^{x}\left(q_{(o,g)}^{[L,H]}(P_i,t,K_1) + q_{(o,g)}^{[L,H]}(P_i,t,K_2)\right). \tag{3}$$

The REA/MMS constructs production profiles for the WGOM and CGOM planning regions, and the following observations are derived from profiles provided by the MMS (Desselles, 2001b).

1. (a) The production profile $q_{(o,g)}(P_i,t,K_1)$ recovers the resource category $K_1(P_1)$ = $R_1(P_1)$ + $R_2(P_1)$ + $R_3(P_1)$ according to an *average* profile since it is not bound through a low and high case scenario.

   (b) The annual production profile $q_{(o,g)}(P_i,t,K_1)$ recovers proved reserves, unproved reserves, and reserves appreciation beginning at time τ = 2001 under an exponentially declining and smooth profile. The recovery time of the profile is assumed to be essentially the time horizon of the forecast.

   (c) The production forecast for class K_1 recovers 94% of the oil and all of the natural gas unproved reserves and reserves appreciation values estimated to exist in the WGOM. Similar recovery percentages are achieved in the CGOM.

   (d) $R_2(P_i)$ is recovered according to a low and high case scenario using a bell-shaped curve that reaches its peak within roughly seven years and decays to zero over a 30-year horizon. The low and high case scenarios represent scaled versions of one another which peak at approximately the same time.

   (e) The annual production curves that recover $R_2(P_i)$ are "normalized" in the REA procedure. Normalization is used to adjust the production profile to "match" the estimate of the resource base.

2. (a) To recover undiscovered economically recoverable resources, the REA/MMS employs a procedure where the production profiles used to recover $R_5(P_1)$ are decomposed into a "proposed" and "future" sales category which begins recovery within three and four years, respectively, of the current time. Proposed sales represents approximately 7% of the estimated total oil resources and 8% of the estimated natural gas resources within the category.

   (b) The recovery curves $q_{(o,g)}^{[L,H]}(P_i,t,K_2)$ are smooth and bell-shaped reaching their maximum recovery rates near the year 2030 for both oil and gas. The production profiles for the low and high case scenario are approximately scaled versions of one another; i.e.,

$$q_{(o,g)}^{H}(P_i,t,K_2) \approx \alpha\, q_{(o,g)}^{L}(P_i,t,K_2), \text{ for } \alpha > 1.$$

   (c) The REA hydrocarbon production forecast recovers a fraction of the undiscovered resource base in the WGOM. More precisely, (31%, 35%) of the oil resources and (46%, 58%) of the gas resources in the K_2 category are recovered over the time horizon of the forecast. The recovery rates of K_3 are slightly higher in the CGOM region: (41%, 54%) for oil and (62%, 91%) for gas. Refer to Table A.1.

3. (a) The REA allocates (41%, 45%) of the total oil resources and (66%, 73%) of the total gas resources within the WGOM over a 40-year horizon. In the CGOM, (61%, 64%) of the total oil resources and (83%, 95%) of the total gas resources are recovered. Oil recovery is underestimated relative to gas resources, and gas recovery percentages exhibit a larger spread. In terms of BOE recovery rates, the percentage values are a weighted average of the oil and gas recovery rates and converge in value: (56%, 60%) of the WGOM resources are recovered and (73%, 85%) of the CGOM resources are recovered.

   (b) The cumulative curves for the WGOM imply that the REA "implicit" forecasts is that between 63% (low) to 50% (high) of the oil resources, and between 57% (low) to 52% (high) of the gas resources, will be recovered within 20 years[5].

Production profiles constructed for oil and natural gas can be compared to other industry supply forecasts, such as those performed by the Gas Research Institute, National Petroleum Council, American Gas Association, and U.S. Department of Energy. A direct comparison of production forecasts should be approached cautiously, however, since the estimates of the resource base and underlying assumptions of the various models are not likely to be compatible; e.g., industry forecast generally tend to be "optimistic" relative to government assessments, although even government forecast have occasionally been criticized as being too optimistic (e.g., see (Attanasi, 2001)).

[5] The estimated amount of resources to be recovered varies under the low and high case scenarios, and hence, the percentage recovery rates depend upon both the conjectured production profiles and the estimated resource base. Since these quantities are independent of one another, it is *not* necessary that the "high" recovery percentage exceed the "low" recovery percentage values.

1.2.4. The Infrastructure Forecast: The hydrocarbon production profile is one of three forecasts required to drive the platform infrastructure requirements. Two additional forecasts are required to determine the number of structures installed and removed. In reference to the four-step procedure outlined in Chapter 1.2.1, we now focus on *Steps 2-4*:

The total annual production profile in planning area P_i in year t is denoted by $q(P_i, t)$ and the number of active platforms is designated by $A(P_i, t)$. A forecast is denoted by a superscript *, so that for instance,

$q(P_i,t)^*$ = Forecast of the annual production profile in P_i

$\left(\frac{q(P_i,t)}{A(P_i,t)}\right)^*$ = Forecast of the annual production per active platform ratio in P_i .

The REA employs the forecast $q(P_i,t)^*$ and $\left(\frac{q(P_i,t)}{A(P_i,t)}\right)^*$ to determine the number of active platforms that are required to meet the production projection. The number of active platforms is established by multiplication:

$$q(P_i,t)^* \left(\frac{q(P_i,t)}{A(P_i,t)}\right)^* = A(P_i,t)^*, \tag{4}$$

and using the forecasted number of active platforms, $A(P_i,t)^*$, and a conjectured relation on the ratio of installed-to-removed platforms, $i(P_i,t):r(P_i,t)$, to satisfy the relation

$$A(P_i,t)^* = A(P_i,t-1)^* + r(P_i,t)^* - i(P_i,t)^*. \tag{5}$$

The annual number of installed and removed platforms required to achieve balance is estimated based on historic installed-removed ratio patterns and life-cycle analysis.

1.3. Critique of the MMS Methodology

1.3.1. A Critique of the Production Profile Forecast: Production forecasts are notoriously difficult to perform regardless of the individual, agency, or organization. A production forecast is based upon the best information available at the time and must be considered under the economic conditions projected for the future, including assumptions regarding inflation and technological improvements. It is important to carefully delineate all assumptions and decision parameters in a forecasting procedure. Based on REA/MMS methodology, the following observations are provided.

1. (a) The National Assessment of the remaining proved reserves in the WGOM is stated as a point estimate of 0.495 Bbbl oil and 7.393 Tcf gas (see Table A.1).

The REA bounds these values through the selection of a low and high case scenario which is not compatible with the manner in which the data is reported. To employ the point estimates it is suggested that appropriate assumptions be specified.

(b) For the estimated proved reserves, bounds on the recovery rate (not on the magnitude) of $R_1(P_1)$ and $R_2(P_1)$ may be desirable; e.g., the form of the low and high case profiles $q^H_{(o,g)}(P_1, t, K_1)$ should not necessarily be scaled versions of one other; i.e.,

$$q^H_{(o,g)}(P_1, t, K_1) \neq \alpha q^L_{(o,g)}(P_1, t, K_1), \text{ for } \alpha > 1. \tag{6}$$

The magnitude of the total recovery for the low and high case profiles, however, should be identical:

$$\sum_{t=\tau}^{\tau+40} q^L_{(o,g)}(P_1, t, K_1) = \sum_{t=\tau}^{\tau+40} q^H_{(o,g)}(P_1, t, K_1). \tag{7}$$

(c) Reserves appreciation are reported in terms of a point quantity and the profile that recovers the appreciation is reported as a single curve. This is logically consistent, but considering the resource class under assignment (and the magnitude and uncertainty associated with its recovery and development), bounds on the recovery rate of this resource class may be desirable.

2. (a) $R_5(P_1)$ is recovered according to scenarios based on "proposed" and "future" leasing to account for specific lease sale alternatives required for economic and environmental impact assessment.

(b) In the construction of the production profiles $q^{[L,H]}_{(o,g)}(P_1, t, K_2)$, the uncertainty associated with the profile appears to be due almost entirely to the uncertainty in the estimated magnitude of $R_5(P_1)$ in the F95 and F5 estimates. Since the production profile is also highly uncertain with regard to development time and investment activities, this uncertainty should be incorporated, if possible, in the forecast scenarios.

3. (a) For the resource categories K_1 and K_2, resources should be recovered at the amount estimated in the National Assessment or at a specified percentage of the value, and this value should be stated explicitly. The percentage values may vary as a function of water depth and planning area, but for consistency the "decision parameters" should be clearly stated for each category.

(b) From the cumulative productive profile for $R_T(P_1)$, a given recovery rate can be inferred. This "implied recovery" could be combined with a 2-parameter supply model to simplify the construction of the supply profiles while incorporating a decision-oriented approach within the modeling framework. The uncertainty associated with the construction of a simplified supply profile and the REA approach is believed to be of the same order of magnitude.

(c) It is desirable that production forecasts performed at the MMS should be consistent in the sense that the first five years of the REA/MMS 40-year production profile should coincide with the MSM short-term forecast profile (Melancon *et al*., 2001)

<u>1.3.2. A Critique of the Infrastructure Forecast:</u>

1. (a) Platforms are used to process both oil and gas, although in practice, most platforms process either oil or gas, and re-inject, store, or flare the unwanted component. Platforms characterized as either "oil" or "gas" platforms can be used with oil and gas production data, while platforms that are *not* disaggregated according to these categories should use production data on a "BOE" basis. It is not appropriate to mix categories; i.e., to forecast the number of "gas" platforms based on "BOE" production profiles or "platforms" based solely on "oil" production. It is convenient and logical in a first-order assessment to use platforms and BOE data rather than to disaggregate at a lower level, but if separate oil and gas resource forecast are employed, then platforms should be distinguished by class.

(b) A "platform" is very broadly defined and should be disaggregated in a manner compatible with the application of the forecast. Although all platforms support production, they do so in a number of ways; e.g., there are production platforms, quarter platforms, storage platforms, transportation platforms, and combinations of these types, as well as caissons and well-protector jackets which would not generally be considered a "platform" at all. It is desirable to distinguish structures into configuration type to differentiate the economic and environmental impact of installation and removal. One possible categorization is through major and nonmajor structure classifications[6]. Failure to account for the structure type will bias the forecast and the resultant levels of economic and environmental activity.

(c) The water depth and planning area categorization employed in the forecast is considered appropriate to group entities into "reasonably" homogeneous categories.

(d) The REA appears to construct supply profiles over a planning area basis which is not compatible or logically consistent with the water depth categories employed in the infrastructure forecast. A supply profile

[6] Major structures are defined as having at least six completions *or* two pieces of production equipment, while nonmajor structures do not satisfy either of these requirements. Major structures thus include platforms or satellites with six completions or more, or at least two pieces of production equipment such as braced caissons, conventional piles with wells, skirt platforms, and floating platforms. Caissons and well protector jackets surrounding five wells or less and conventional piled platforms without wells (e.g., quarters platforms, storage platforms, pipeline junction and metering facilities) would be considered nonmajor structures.

constructed over a planning area basis cannot drive a forecast through depth categories unless appropriately disaggregated.

2. (a) The annual production per active platform is a function of time, and to be used across a water depth categorization the functional needs to be computed and forecast across each individual water depth category.

   (b) The REA uses a five year moving average to reduce the volatility of the annual production per active platform ratio and this is acceptable as long as the forecast of the moving average is based on historic trends. Conjectured trends are acceptable as long as they are a clearly specified decision parameter.

3. (a) The forecasted number of active platforms is determined through the product of the forecasted supply profile and platform-production ratio profile. From the forecast of active platforms, the annual platform installation and removal rates are determined to achieve balance with this number, but to "achieve balance" requires an additional assumption on the installation and removal trends in a given region. Determining the normalization factor is difficult since the historical trends on installation and removal patterns are dynamic quantities with a large standard deviation. The transition from an estimate of active platforms to an estimate of installed and removed platforms is subject to significant uncertainty.

1.4. Ten Recommendations

A platform forecast should be performed in a manner compatible with the system data and the intended use of the forecast. In economic and environmental impact studies for instance, where the number of platforms expected to be installed and removed in a given region is the primary input factor to assess the impact on surrounding communities, the forecast must be performed at a fairly low level of aggregation for the results to be meaningful. Since platforms are diverse by nature, it is not logical to categorize a well caisson and a fixed platform as similar GOM "structures." Separate forecasts must be performed over distinct category sets, and it is neither necessary nor desirable[7] to apply the same type of forecast to each category. Since several decision parameters are implicitly stated throughout the REA procedure, it is also desirable to make these assumptions explicit and to try to relate the uncertainty associated with the forecast with the input parameters of the decision maker. And since the number of categories and decision parameters for this problem is large, an automated procedure is essential. An automated decision-oriented framework is possible only if a structured and well-defined environment has been created for this purpose.

[7] In fact, requiring the same forecasting methodology over each category imposes an unnecessarily tight constraint on the procedure which defeats the purpose of disaggregation.

Ten recommendations follow.

1. The notion of being able to recover a fixed resource "bundle" (e.g., $R_1(P_1)+R_2(P_2)+R_3(P_2)$) at a given rate (e.g., $q_o^L(P_1,t,K_1)$) beginning at a specific time is entirely hypothetical. Resources flow between and within categories in ways that are not predictable or quantifiable. Reality is better explained in a dynamic manner in terms of a flow (Adelman, 1996):

   > "Mineral production is a flow from an unknown physical resource, first through exploration from "basins" to "plays," then into identified "fields" and "reservoirs," then through development into current inventories or "proved reserves," to be extracted and sold. Reserves are renewable and constantly renewed, if and only if there is enough inducement to invest in creating them."

   Bundling resources is nonetheless a *convenient* mechanism that helps establish a structured environment in which to perform a production forecast, and it is a justifiable and viable method in the construction of supply curves. Platform activity is driven by trends in discoveries, which is conditional on geologic and economic factors. It is recommended that the REA/MMS resource-based approach be refined, clarified, and automated in a decision-structured environment.

2. A more structured presentation of the production profile should be established with all assumptions and decision parameters specified, the methodology performed in a step-by-step and explicit fashion, and the forecast performed across individual water depth categories. Structured approaches do *not* necessarily imply that the resulting forecasts are more accurate, but rather, the results of the forecast are *consistent* with the assumptions and parameters selected for the model. Structured models help to avoid mixing assumptions that are inconsistent and/or incompatible, clarify uncertainty, and are easier to defend/analyze since the user understands the limitations of the methodology and the implications of the variability. Assumptions delineate uncertainty but do not (nor can not) eliminate it. Structural models are useful to quantify uncertainty and also provide a framework to perform sensitivity analysis.

3. Establish bounds on the *rate* of recovery of the production curve $q_{(o,g)}(P_1,t,K_1)$ to recover the resources in category $K_1 = \{R_1(P_i) + R_2(P_i) + R_3(P_i)\}$ under a low and high case scenario.

4. The REA/MMS production profiles are likely to be underestimated due to the conservative estimates associated with the magnitude of resource recovery. Full recovery of each resource category should be made, or the percentage of the resource allocation be declared as a decision variable and specified across each water depth category. Allocation levels that are not specified appear arbitrary, while variable allocations that are specified appear reasoned; the uncertainty is the same in either case, but in the later approach the method is justified.

5. The construction of the REA supply profiles can be simplified in terms of a 2-parameter decision model where the decision maker specifies the amount of $R_T(P_i)$ that is expected to be recovered (the first parameter) within a particular time frame (the second parameter). This will help to clarify the exposition and simplify the forecast across multiple water depth categories; the downside of the approach is erosion of the link between policy variables (e.g., lease sales) and production profiles.

6. The notion of forecasting an entity labeled a "platform" is troublesome since the category is too broadly-defined and encompasses widely disparate infrastructure. The selection of the appropriate classification category is determined by the application of the forecast. For economic impact studies, the platform as a physical structure (wells, deck and jacket) as well as the topsides production and drilling equipment provides the stimulus for the economic impact. A logical classification can be made in terms of "major" and "nonmajor" structures. For environmental impact studies, the potential biomass and habitat provided by a structure between the waterline and the mudline is the relevant parameter, and so the size and platform construction would be the appropriate aggregation category; e.g., conventionally-piled platforms with *n*-piles provides a measure of the complexity of the structure. Alternative platform classifications are also desirable since "oil" and "gas" structures could be directly linked to oil and gas production profiles.

7. Planning areas need to be disaggregated in terms of water depth categorization since the entities of the forecast are not homogeneous across water depth. Production profiles are currently performed over a planning area basis, but to drive an infrastructure forecast across water depth, it is necessary to construct production profiles on a water depth basis.

8. If resource estimates can be reported over lower levels of categorization; e.g., 0-60m, 61-200m, then additional categorization of the structure data may enhance understanding of the platform installation and removal rates. National Assessment resource data are currently reported using categories 0-200m, 201-800m, etc.

9. Annual short-term and long-term infrastructure forecast should be documented, the model assumptions clearly specified, and the forecast results formally evaluated so that institutional memory and experience improves forecast performance.

10. The REA method of platform forecasting should be analyzed in conjunction with the CES methodology and converged into a "best practice" model.

1.5. The CES Infrastructure Forecast Methodology

1.5.1. The CES Infrastructure Forecasting Procedure: The infrastructure forecast methodology proposed by the CES/LSU is a four-step procedure based in part on the structure of the REA/MMS approach. A formal treatment of the methodology is described as follows:

Step 1. Construct cumulative hydrocarbon production profiles on a BOE basis per water depth and planning area category over a 40-year time horizon

Step 2. The cumulative number of major and nonmajor structures installed and removed per cumulative BOE production on a water depth and planning area basis is forecast over a 40-year time horizon.

Step 3. The cumulative number of structures installed and removed over each water depth and planning area category is determined by the product of the profiles determined in *Step 1* and *Step 2*.

Step 4. The annual number of major and nonmajor structures installed and removed are derived from the cumulative forecast in *Step 3*.

1.5.2. The Cumulative Production Profile: To perform a resource-based infrastructure forecast on a water depth and planning area basis requires the user to construct a production profile forecast over a similar water depth and planning area basis. The REA currently performs a supply profile forecast over three planning areas; in the CES approach this is replaced by nine supply forecasts (one for each planning area and water depth category: 0-200m, 201-800m, 800+m). The CES approach employs a decision-oriented construction, requesting the user provide the following information:

What percentage of $R_T(\Gamma_{i,j})$ will be recovered within the time horizon τ?

The recovery of the remaining conventionally recoverable resources is thus based on the *belief* of the decision maker. Two input parameters are required: the percentage of $R_T(\Gamma_{i,j})$ to be recovered (the first parameter) within the time horizon τ (the second parameter). The application of a 2-parameter supply profile not only simplifies the construction of the profiles, but also creates a framework to perform sensitivity analysis.

1.5.3. Expression for the Number of Active Platforms: The number of active platforms operating in the water depth and planning area region $\Gamma_{i,j}$ at time t is denoted $A(\Gamma_{i,j},t)$. The number of active platforms is a dynamic quantity and is computed on an annual basis in terms of the relation

$$A(\Gamma_{i,j},t)=A(\Gamma_{i,j},t-1)+i(\Gamma_{i,j},t)-r(\Gamma_{i,j},t), \qquad (8)$$

where $i(\Gamma_{i,j},t)$ and $r(\Gamma_{i,j},t)$ represent the annual number of platforms installed and removed in region $\Gamma_{i,j}$ over the time interval (t-1,t]. In words, relation (8) indicates that the number of platforms active at time t, $A(\Gamma_{i,j},t)$, is equal to the number of platforms active in the previous year, $A(\Gamma_{i,j},t\text{-}1)$, plus the number of platforms installed minus the number of platforms that were removed over the past year (t-1, t], $i(\Gamma_{i,j},t)$ and $r(\Gamma_{i,j},t)$.

Initially there are no platforms active; i.e., the boundary condition is defined as follows:

$$A(\Gamma_{i,j},0)= 0; \tag{9}$$

and using the recursive relation (8) we obtain

$$A(\Gamma_{i,j}, 1) = i(\Gamma_{i,j}, 1) - r(\Gamma_{i,j},1), \tag{10}$$

$$\begin{aligned} A(\Gamma_{i,j}, 2) &= A(\Gamma_{i,j}, 1) + i(\Gamma_{i,j}, 2) - r(\Gamma_{i,j}, 2) \\ &= (i(\Gamma_{i,j}, 1) + i(\Gamma_{i,j}, 2) - (r(\Gamma_{i,j},1)+r(\Gamma_{i,j}, 2)) \end{aligned} \tag{11}$$

$$= \sum_{k=1}^{2} i(\Gamma_{i,j}, k) - \sum_{k=1}^{2} r(\Gamma_{i,j}, k). \tag{12}$$

The general relationship is thus

$$A(\Gamma_{i,j},t) = \sum_{k=1}^{t} i(\Gamma_{i,j},k) - \sum_{k=1}^{t} r(\Gamma_{i,j},k). \tag{13}$$

If $I(\Gamma_{i,j},t)$ and $R(\Gamma_{i,j},t)$ denote the cumulative number of structure installation and removals through time t; i.e.,

$$I(\Gamma_{i,j},t) = \sum_{k=1}^{t} i(\Gamma_{i,j},k),$$

$$R(\Gamma_{i,j},t) = \sum_{k=1}^{t} r(\Gamma_{i,j},k),$$

then relation (13) can be expressed more compactly as

$$A(\Gamma_{i,j},t) = I(\Gamma_{i,j},t) - R(\Gamma_{i,j},t). \tag{14}$$

In words, relation (14) expresses the number of active platforms in region $\Gamma_{i,j}$ at time t, $A(\Gamma_{i,j},t)$, as the difference in the cumulative number of platforms installed and removed through time t, $I(\Gamma_{i,j},t)$ and $R(\Gamma_{i,j},t)$.

1.5.4. The CES Methodology: The REA approach to infrastructure forecasting employs the number of active platforms to annual production ratio,

$$\frac{A(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)}, \tag{15}$$

to determine the number of active platforms required to recover the anticipated production. Using relation (14), the ratio (15) is written equivalently as

$$\frac{A(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)} = \frac{I(\Gamma_{i,j},t) - R(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)} = \frac{I(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)} - \frac{R(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)}. \tag{16}$$

Observe that the numerator and denominator terms in (16) are "mixed" in the sense that the numerator is a cumulative measure while the denominator is an annual factor. Formally, the measure is well-defined, but methodologically it is desirable to have the numerator and denominator of the same type (annual or cumulative, but not both).

The CES approach to platform forecasting first modifies the denominator in the ratio (15) to its cumulative form:

$$\frac{A(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)} = \frac{I(\Gamma_{i,j},t) - R(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)} = \frac{I(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)} - \frac{R(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}, \tag{17}$$

and then decomposes the expression in terms of two separate functionals

$$\frac{I(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}, \quad \frac{R(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}. \tag{18}$$

The CES approach then follows the REA procedure and forecasts the supply profile $Q(\Gamma_{i,j},t)$ (see Chapter 1.5.2) and the functionals (18) over a 40-year horizon. The forecast of each of the functionals are denoted with a superscript * as follows:

$$Q(\Gamma_{i,j},t)^*, \left(\frac{I(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^*, \left(\frac{R(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^*. \tag{19}$$

The product of the production and ratio forecast provides an estimate of the cumulative number of platforms installed and removed; i.e.,

$$Q(\Gamma_{i,j},t)^* \cdot \left(\frac{I(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^* = I(\Gamma_{i,j},t)^*,$$
$$Q(\Gamma_{i,j},t)^* \cdot \left(\frac{R(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^* = R(\Gamma_{i,j},t)^*. \quad (20)$$

The output functionals $I(\Gamma_{i,j},t)^*$ and $R(\Gamma_{i,j},t)^*$ are then used to compute the annual installation and removal rates using backward recursion

$$I(\Gamma_{i,j},t)^* - I(\Gamma_{i,j},t-1)^* = i(\Gamma_{i,j},t)^*, \quad (21)$$

$$R(\Gamma_{i,j},t)^* - R(\Gamma_{i,j},t-1)^* = r(\Gamma_{i,j},t)^*. \quad (22)$$

By starting at the end of the time horizon and working through to the present year-by-year, the annual number of installation and removal rates are calculated using (21) and (22).

1.5.5. A Comparison of the CES and REA Forecast Methodologies: The CES/LSU and REA/MMS approach to infrastructure forecasting are both resource-based and driven by historical system characteristics and explicitly defined decision parameters. The primary distinction between the two approaches is as follows.

- The CES approach partitions the GOM into water depth and planning area categories, $\Gamma_{i,j}$, and performs a BOE cumulative production forecast over each category. The decision parameters (p, θ) are employed to simplify the construction of the production profile, where the parameter p indicates the percentage of the total resource $R_T(\Gamma_{i,j})$ to be recovered within a time period θ years from the present. The REA approach determines individual production profiles for the resource classes $R_1(P_i)$, $R_2(P_i)$, $R_3(P_i)$, and $R_5(P_i)$ over the planning area category P_i for both oil and natural gas, and then computes the total economically recoverable resource profile, $R_T(P_i)= R_1(P_i)+ R_2(P_i)+ R_3(P_i)+ R_5(P_i)$.

- The CES approach disaggregates platforms in terms of major and nonmajor structures and forecasts each category separately while the REA approach employs the general platform categorization.

- The REA approach develops the ratio of the annual production, $q(P_i, t)$, to the annual number of active platforms, $A(P_i, t)$, within planning area P_i:

$$\frac{q(P_i,t)}{A(P_i,t)}, \tag{23}$$

while the CES approach applies the cumulative number of (major, nonmajor) structures installed and removed over the cumulative production in region $\Gamma_{i,j}$:

$$\frac{I^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}, \quad \frac{R^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}. \tag{24}$$

- The REA forecasts $q(P_i, t)^*$ and the ratio

$$\left(\frac{q(P_i,t)}{A(P_i,t)}\right)^*, \tag{25}$$

while the CES approach forecasts each of the functionals

$$\left(\frac{I^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^*, \quad \left(\frac{R^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^*. \tag{26}$$

separately.

- The REA forecasts the number of active platforms to support a given production profile by multiplying a forecast of the annual production, $q(P_i, t)^*$, by (the inverse of) the forecasted ratio $(q(P_i, t)/A(P_i, t))^*$, to yield the number of active platforms:

$$q(P_i, t)^* \cdot \left(\frac{A(\Gamma_{i,j},t)}{q(\Gamma_{i,j},t)}\right)^* = A(P_i, t)^*. \tag{27}$$

The CES approach forecasts the cumulative supply curve $Q(P_i, t)^*$ over the water depth and planning area category $\Gamma_{i,j}$, and then multiplies the cumulative profile by a forecast of the infrastructure requirements ratio:

$$Q(\Gamma_{i,j}, t)^* \cdot \left(\frac{I^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)}\right)^* = I^{[m,n]}(\Gamma_{i,j},t)^*, \tag{28}$$

$$Q(\Gamma_{i,j}, t)^* \cdot \left(\frac{R^{[m,n]}(\Gamma_{i,j},t)}{Q(\Gamma_{i,j},t)} \right)^* = R^{[m,n]}(\Gamma_{i,j},t)^*,$$

to yield the cumulative number of major and nonmajor structures installed and removed over $\Gamma_{i,j}$, $I^{[m,n]}(\Gamma_{i,j},t)^*$ and $R^{[m,n]}(\Gamma_{i,j},t)^*$.

- The CES approach employs the cumulative installation and removal functionals per major and nonmajor structure to *derive* the annual installation and removal rates and active platforms per category $\Gamma_{i,j}$. The annual future platform installation and removal rates, $i^{[m,n]}(\Gamma_{i,j},t)^*$ and $r^{[m,n]}(\Gamma_{i,j},t)^*$, are computed directly from $I^{[m,n]}(\Gamma_{i,j},t)^*$ and $R^{[m,n]}(\Gamma_{i,j},t)^*$:

$$I^{[m,n]}(\Gamma_{i,j}, t)^* - I^{[m,n]}(\Gamma_{i,j}, t-1)^* = i^{[m,n]}(\Gamma_{i,j},t)^*, \tag{29}$$

$$R^{[m,n]}(\Gamma_{i,j}, t)^* - R^{[m,n]}(\Gamma_{i,j}, t-1)^* = r^{[m,n]}(\Gamma_{i,j},t)^*. \tag{30}$$

Since active platforms are defined in terms of platform installation and removal rates, $i^{[m,n]}(\Gamma_{i,j},t)^*$ and $r^{[m,n]}(\Gamma_{i,j},t)^*$ are then used to compute $A^{[m,n]}(\Gamma_{i,j},t)^*$:

$$A^{[m,n]}(\Gamma_{i,j}, t)^* = A^{[m,n]}(\Gamma_{i,j}, t-1)^* + i^{[m,n]}(\Gamma_{i,j},t)^* - r^{[m,n]}(\Gamma_{i,j},t)^*. \tag{31}$$

The REA approach employs a conceptually intuitive measure – the annual production per active platform – to forecast the number of active platforms, but is then required to employ additional assumption to determine the annual installation and removal rates. The number of platforms that will be installed and removed to achieve the number of active platforms is then *estimated* based on historic patterns and life-cycle analysis. The CES approach employs a more complex and less-intuitive functional – the cumulative installation and removal rate per cumulative production – but then *derives* the annual number of installed and removed platforms *without* the need to invoke additional assumptions. The trade off between the two approaches is comparable.

1.6. Conclusions

Forecasting is a traditional blend of art and science, and under conditions of unknown uncertainty, it is desirable to maintain a consistent, simplistic, and structured methodology that explicitly enumerates the assumption set and does not mix scenario assumptions or introduce additional uncertainty external to the modeling framework. Infrastructure forecast deserve careful attention to detail and deliberate methodological development, and should be performed on a regular basis to develop a better understanding of the system drivers and limitations of the analysis. The REA/MMS has done a good job in developing and promulgating the GOM platform forecast, and as discussed in this paper, the main criticism is aimed at refining the methodology, explicitly enumerating the assumption set, and ensuring that the solution methodology is consistent within the model framework. A set of recommendations was described addressing these concerns.

The methodology suggested in Chapter 1 is an adaptation of the REA approach that formalizes the framework in a consistent manner, modifies some key elements of the methodology, and incorporates decision parameters within the procedure. A formal development of the proposed methodology was presented and compared with the REA approach. Comparison of the two approaches illustrates that the REA and CES procedures represent a trade-off between the preferences of the user and the assumptions of the methodology. It is suggested that the two procedures evolve into an automated "best practice" model.

CHAPTER 2: A DECISION- AND RESOURCE-BASED APPROACH TO LONG-TERM INFRASTRUCTURE FORECASTING IN THE GULF OF MEXICO

2.1. Introduction

Platforms and pipelines are the primary infrastructure used to develop and transport hydrocarbons in the Gulf of Mexico (GOM). Platforms represent the visible signatures of production with pipelines their invisible partner. A wide variety of platforms, or more generally, structures, are used in gulf waters to support the equipment used for drilling wells, processing hydrocarbon production, or housing offshore personnel. Offshore structures are designed under specific environmental conditions and operator loads, and although it is difficult to classify all configurations, most structures may be characterized as caissons, well-protector jackets, conventionally piled fixed platforms, and floating structures. Knowledge of the number of structures expected to be installed and removed in offshore waters is of primary importance in the U.S. Minerals Management Service (MMS) responsibility to manage the oil and gas activities on the Outer Continental Shelf (OCS) of the GOM.

The purpose of Chapter 2 is to develop a methodological framework to forecast structure installation and removal rates in the GOM over a 40-year time horizon. The framework is based on a model structure developed by the Resource and Evaluation Analysis Unit (REA) of the MMS (Desselles, 2001a and b), but departs from the REA approach in terms of the level and type of disaggregation employed and the methodology used to construct the forecast. For a description of the REA model and its relation to the CES approach, see Chapter 1 for additional information.

The number of structures required to develop a field is affected by a number of factors, including but not necessarily limited to, the expected size of the field, the number of productive wells drilled from each platform, the amount of oil/gas each productive well produces, environmental factors such as water depth, soil conditions, and storm intensity, capital cost, availability of platforms, and strategic opportunity. The emphasis of this Chapter is to present a decision- and resource-based framework to an infrastructure forecast in a manner subject to an explicit set of assumptions.

The outline of Chapter 2 is as follows. Background information is provided in Chapter 2.2. In Chapter 2.2.1, the demand for infrastructure in the GOM is described, followed in Chapter 2.2.2 by a brief discussion for the need for an infrastructure forecast. In Chapter 2.2.3, the definition and classification of structures is reviewed followed in Chapter 2.2.4 by a critique of platform forecast methodologies. General methodological issues are presented in Chapter 2.3. The motivation for disaggregating data is described in Chapter 2.3.1 and special reference to the primary constraints of disaggregation is discussed in Chapter 2.3.2. In Chapters 2.3.3 and 2.3.4, the basic principles of forecasting are enumerated and the general methodology is described. A decision- and resource-based forecast model is then presented in Chapter 2.4. In Chapter 2.4.1, the general infrastructure forecasting methodology is described, followed by a description in Chapters 2.4.2 and 2.4.3 of the two key steps of the forecast, namely, constructing the supply profile and forecasting the infrastructure requirements ratio. Model results and a general interpretation of the procedure are presented in Chapter 2.4.4. Limitations of the analysis and suggestions for further research are presented in Chapter 2.5. In Chapter 2.6, conclusions complete the paper.

2.2. Background Information

2.2.1. The Demand for Infrastructure in the Gulf of Mexico: The oil and gas industry has operated along the Gulf Coast for nearly 100 years, beginning with overwater drilling at Caddo Lake, Louisiana, in 1905. To be able to drill and produce without direct contact to the land, construction engineers at Caddo Lake drove pilings into the bottom of the lake bed to provide support for the platforms. Barges transported drilling equipment and supplies to the drill site, and underwater pipeline connected the producing wells to gathering stations on the lake (Pratt *et al*., 1997). The first offshore platform was installed in the Gulf of Mexico in 1947 in about 5m of water (Kerr-McGee, Ship Shoal Block 32), while today, drilling and production companies are moving into the ultradeepwaters of the gulf in depths approaching 3,000m (Baud *et al*., 2000).

Platforms and pipelines are the primary infrastructure required to develop and transport hydrocarbons. Platforms either stand on the sea bottom or float on the sea surface, and hold the equipment required to treat and process the produced fluids, including drilling equipment, cranes, compressors, power generators, etc. Structures provide the foundation for surface facilities and serves as the "ground" in offshore development, while pipelines are used in gathering systems, moving fluids between facilities within and between fields, and for final transport away from the field to market[8]. In deep waters well platforms are connected by pipeline to a facilities platform where processing takes place. Wells, facilities, and quarters are kept on separate platforms, if possible, for safety reasons, but as the water gets deeper and platform jackets become more expensive, well, facility, and quarters' platforms are normally combined into a single super structure. Platform costs escalate with increasing water depth and shift the economics away from wells with individual jackets toward multiple wells drilled from a single platform and subsea wells tied back to a host facility (Conaway, 1999).

Platform and pipeline infrastructure development in the offshore Gulf of Mexico is closely associated with field development but the correlation depends on a complex array of factors which are not readily quantified. The shallow waters of the GOM is a mature offshore region with the most highly developed infrastructure in the world, while deep water development is still considered a frontier region with virtually no supporting infrastructure (Baud *et al*., 2000). The dynamics of deepwater development are also quite different than shallow water fields, both in terms of production characteristics, development costs, cash flow streams, development time, and technology applications. While shallow water wells are commonly associated with individual structures, deepwater

[8] All the natural gas in the GOM, and practically all the oil, is transported via pipeline to shore.

platforms are normally developed as a "hub" to serve several wells, and increasingly, more than one field. The number of producing wells per active platform as shown in Table B.1 is one measure that captures this trend. Recent technological advances in field development such as extended reach, directional drilling, multilateral and subsea completions continue to reduce the number of platforms necessary to develop a field.

The demand for infrastructure in the Gulf of Mexico, and in particular, the demand for a structure is a function of the outcome of the discovery process, when and where the field is discovered, and the development plan of the companies involved with the discovery. The development plan is a critical factor and closely tied to the expected size of the field, the field's geographic location relative to existing infrastructure, and the potential to support future development. These demand variables in turn are influenced by factors such as the fields ranking within the company's portfolio of plans and geologic conditions in the area, which in turn depend upon the price and demand for oil and natural gas, the impact of regulatory action, and global economic conditions.

Basic economics imply that if a well or collection of wells can produce enough oil or gas to cover the cost of completion, operating costs, and a favorable return, then it will be put into production and a platform will be installed. Given the enormous front-end investment cost oil companies make in bidding for drilling rights, exploration, and development, there is considerable financial incentive for rapid field development. On the other hand, near the end of the life of a field when the drive mechanism and production decline are well understood, a structure will be maintained as long as possible given that it exists as an asset and not a liability; i.e., cost are adequately covered. The parameters associated with installation decisions are mostly uncertain, however, and so investment opportunities are usually risked and individual projects ranked in accordance with a priority list.

If the field is large enough and falls within the economic-risk criteria of the company portfolio and budgetary constraints, then a platform is the usual course of development. Smaller fields, or fields sufficiently removed from existing infrastructure, are usually not cost-effectively developed with a platform but may be completed with subsea technology tied-back to existing infrastructure. In the ultradeepwaters of the GOM, infrastructure is sparse and pipeline costs can be a significant factor in the overall cost of development. The anticipated use of floating production storage and offloading units may play an important role in future deepwater production which will further act to distort "traditional" platform-production characteristics.

The impact of technology on field development is pervasive and difficult to quantify. A field can now be developed without building a new platform as long as a tie-back to an existing structure is economically feasible. Subsea completions, where the wellheads are installed at the mudline and connected by pipeline with nearby platforms, increase the number of small fields that can be developed without a platform. Additional technological advances such as directional drilling, horizontal drilling, slimhole drilling, 3-D and 4-D seismic, improved drill bits, advanced synthetic drilling fluids, and corrosion resistant alloys improve completions, offshore and deepwater drilling, and provide more efficient reservoir management that act to reduce the number of new structures that need to be installed.

2.2.2. The Need to Forecast Infrastructure: Platform forecasting in the GOM is used as a guide to activity levels and as input to economic and environmental impact studies of oil and gas development (Coffman *et al*., 2001; Olatubi and Dismukes, 2002; Skolnik and Holleyman, 2002; USDOI, MMS, 2001). The need to forecast infrastructure development is thus primarily viewed in terms of its economic and environmental impact. In terms of economic development, platforms need to be constructed, delivered, installed, and equipped prior to production, operated and serviced during production, and then eventually decommissioned and removed after production. Each of these activities has both a direct and indirect impact on the communities in which the service facilities and manufacturing operations are located, and hence induce a "spill-over" effect on the economic growth and vitality of the regions which serve the development; e.g., see (Olatubi and Dismukes, 2002; Skolnik and Holleyman, 2002). An entire industry has been built in the GOM around installing production equipment and structures, servicing those structures (maintenance, repairs, supply), and then removing the structures when production ceases. In terms of environmental impact, the installation of structures and pipelines and production of hydrocarbon may have an adverse effect on the habitat and surrounding communities in the GOM; production activities may result in oil spills, air pollution, and other environmental impacts; and during decommissioning, marine habitat is lost and sea turtles, dolphins, and sperm whales may be at risk if explosives are used for severance operations.

2.2.3. The Importance of Categorization: Generally speaking, the application of the forecast indicates the level of categorization that should be employed. For economic impact models the aggregation level should be able to distinguish between the cost of structures, and one convenient way to do this is by identifying the structure configuration type, its topside inventory, and location (water depth). For environmental impact models on the other hand the categorization level will depend on structural characteristics (number of piles, number of conductors, area of platform) where the emphasis is on the bottomside of the structure and the requirements associated with decommissioning.

A detailed analysis of data which is not carefully screened and properly understood is of little value in modeling and may lead to erroneous conclusions. This is a precautionary statement made in regard to the manner in which structure data is classified. If the categories of aggregation are so broadly defined that the elements within the categories are heterogeneous, then the resultant analysis may not be meaningful. The notion of a "platform" for example is an entity that is so broadly defined (since it encompasses well protectors, satellites, and fixed platforms) that it will lead to bias if used without careful processing. A shallow water platform is not in any sense comparable to a deepwater platform, and although both count as *one* platform in an enumerative sense, there is perhaps a billion dollars difference in average development cost and at least a multiple of this factor in the resultant cash flow streams and their ultimate economic impact[9]. The

[9] Other categorizations are also possible as discussed in Section 6; e.g., gas wells and oil wells are quite dissimilar and may be logical to break out.

application of a water depth categorization partitions configuration type to some extent, but unless structures are specifically identified, they cannot be categorized in a useful manner. Partitioning data into finely selected categories on the other hand tends to introduce a large amount of noise and may also bias the analysis. A degree of balance thus needs to be maintained when selecting the level of aggregation.

The classification strategy employed in this paper is to categorize platforms in terms of “major” and “nonmajor” structures decomposed according to planning area and five water depth categories: 0-200m, 201-800m, 801-1600m, 1601-2400m, 2400^{+}m. The major and nonmajor structure classification and water depth categorization helps to differentiate structures for economic impact studies, while a planning area categorization is useful for locational specificity and to maintain compatibility with area-wide leasing sale proposals.

To maintain the consistency and logical cohesion among the component forecast the class of structures are aggregated using the MMS assignment of “major” or “nonmajor” structure. Major structures are defined as having at least six completions *or* two pieces of production equipment, while nonmajor structures do not satisfy either of these requirements. Major structures thus include platforms or satellites with six completions or more, or at least two pieces of production equipment. This would normally include all braced caissons, conventional piles with wells, skirt platforms, special platforms, and floating platforms (Pulsipher, 1996). Caissons and well protector jackets surrounding five wells or less and conventional piled platforms without wells (e.g., quarters platforms, storage platforms, flare piles, pipeline junction and metering facilities) would be considered nonmajor structures. Platforms may be physically connected by walkways, but if a structure has its own support base then it is counted as a separate entity. Further, a structure may evolve over time from being a caisson, say, to a fixed structure with production equipment. These cases generally occur in only very small numbers, however, and when they do, the most recent structure (which is typically the most complex) is assigned.

2.2.4. Overview of Infrastructure Forecast Methodologies: Infrastructure forecasting can be performed in a variety of ways, but care must be taken to properly define the entities and categories in a manner that does not destroy the information content of the data, induce unforeseen bias in the analysis, or misrepresent the results.

In a previous study performed by the CES (Pulsipher *et al*., 2001), an econometric model for the number of offshore structures operating in the GOM was developed. The total number of structures installed and removed from the GOM was estimated based on regression analysis to be

$$\mathrm{INS}_t = -113.93 + 16.2 \cdot \mathrm{CFZ}_t + 2.09 \cdot \mathrm{P}_t + 0.46 \cdot \mathrm{INS}_{t-1}$$

$$\mathrm{REM}_t = 0.95 \cdot \mathrm{INS}_{t-33} + 0.35 \cdot \mathrm{INS}_{t-21}$$

where,

INS_t = Number of structures installed at time t,

REM_t = Number of structures removed at time *t*,

CFZ_t = Cumulative field size at time *t*, and

P_t = Crude oil price at time *t*.

These relations were then combined with a drilling and discovery process model to forecast the number of structures through the year 2023. The impact of crude oil price variations on the number of active structures was also investigated through price scenarios supported by an EIA forecast. The reader can consult (Pulsipher *et al*., 2001) for a description of the procedures and discussion of the model results.

The MMS also performs platform forecasting (Desselles, 2001a and b) in support of economic and environmental impact studies and other regulatory concerns as described in (Coffman *et al*., 2001). The MMS forecasting procedure is a "resource-based" approach, meaning that the platform requirements necessary to develop the hydrocarbon resources are estimated using hypothetical production profiles that recover an estimated resource base. A "master" hydrocarbon production schedule is conjectured and the infrastructure trends required to support the production are then estimated using historic data and extrapolation techniques. The platform forecast performed by the MMS is at a lower aggregation level than the CES study, occurring over separate water depths and planning regions in the GOM, but as in the CES approach, the MMS does not aggregate the data elements into category types (e.g., major and nonmajor structures).

A review of the advantages, disadvantages, and assumptions of each approach is useful to guide and inform the current methodology. Regression-based models as employed previously in the CES study develop their relationship based on econometric fundamentals and historic data. These relationships are typically determined at a high level of aggregation and attempt to incorporate exogenous factors that influence the installation and removal rates of platforms. By employing data that does not distinguish between geographic location or structure type, however, it is difficult to categorize the model output in terms that are directly relevant for impact studies. In essence, the high level of aggregation destroys the information content of the data since heterogeneous entities are grouped and forecast as similar elements. The data aggregation schemes are easy to revise by constructing regression models over appropriate data subcategories, but the "slicing and dicing" needs to be performed carefully. The application of a discovery process model is also a standard approach to incorporate new field discoveries, but the uncertainty associated with discovery models performed over a large geographic region generally limits their usefulness in practice (Lynch, 2002; National Academy of Sciences, 1991).

The MMS approach drives the infrastructure forecast with a production profile which serves as a substitute for the discovery model. Production profiles are constructed over a planning area and are based on recovering the reserve and resource estimates provided in the National Assessment (Lore *et al*., 2001). Production profiles are relatively easy to construct, but there is also a high degree of uncertainty in the profiles which is not explicitly taken into account. The MMS performs the infrastructure forecast over a lower aggregation level than the CES study, employing planning area and water depth categories, but the production profiles themselves are not performed across the same water depth categories leading to an inconsistent formulation. Recovering the resource base along a production curve also limits the application of some exogenous variables – notably price and technological change – since the inclusion of such factors would not be logically consistent with the form of the resource data[10]. There is also no attempt to distinguish between the type of structures upon which the forecast is based. Since the platform forecast is used as input to economic impact studies which rely upon class demarcation more than merely a "count" of structures, the disaggregation of structures into type is considered essential.

The purpose of this paper is to combine and refine the CES and MMS approaches to platform forecasting to develop a framework that is logically coherent and sensitive to the needs of the user. An infrastructure forecast model is developed for major and nonmajor structures aggregated over a water depth and planning area category and driven production profiles determined in a user decision framework. The impact of technological change is considered a user defined parameter incorporated within the decision parameters of the model. The MMS approach of driving the forecast with a production profile is maintained and careful structure classification allow more meaningful inferences of the model results to be made. The development and exposition of a structured forecasting model serves as the primary task of this paper.

2.3. General Methodological Issues

<u>2.3.1. Selecting the Appropriate Level of Disaggregation:</u> The primary reason to aggregate data is based on modeling philosophy. If processes, activities, or entities (such as discovery rates, formation structures, production profiles, platforms, etc.) are not reasonably uniform within their category of analysis, it is generally agreed that the classification category should be subdivided to create more uniform subcategories in the belief that the categorization will reduce bias in the analysis[11]. The classification scheme employed in this analysis is based on structure type, water depth, and planning area.

The categorization of structure types ensures that the data is properly balanced for economic impact studies. The classification of structures via water depth helps to account for the technology factor and increased economic stimulus associated with increased water depths. Planning areas are also useful to distinguish activity levels associated with the area-wide leasing sale programs.

The process of aggregation and "slicing and dicing" does not always come for "free," however, nor does it necessarily imply that the resultant forecasts are better predictors of the future. Aggregating data over small categories is likely to induce additional variability

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[10] The MMS does not explicitly incorporate price effects or technological change in their supply model, however, and so this restriction is compatible with their approach.

[11] For example, one of the early criticisms from the National Academy of Sciences was specifically directed at the aggregation levels employed by the MMS in their resource evaluation assessments.

since the integrating effects of large data sets are lost. It is generally agreed, however, that the imposition of structure through classification schemes – when the classification is meaningful – improves understanding and helps to identify the limitations of the analysis. In the case of infrastructure forecasting, it is not only logical but necessary to aggregate structures according to water depth and configuration type to accurately account for the nature of installation and removal rates and to better understand the dynamics of development.

2.3.2. Categorization and System Constraints: Aggregation imposes a tight burden on the model structure and the data requirements of the problem. If a forecast is to be performed at a given level of aggregation then the system data must also be available at the same level of aggregation. Unfortunately, this does not usually occur for a variety of reasons.

To perform a resource-based forecast, it is necessary to acquire

1. Resource estimates,
2. Supply forecast, and
3. System data,

at the same level of aggregation. If data is not available at the level of aggregation in which the forecast is to be performed, then the data must either be processed and brought "up" from a "lower" level or partitioned from "above" into the appropriate categories. Data at a low level of aggregation is not always available, however, while reducing high-level data usually involves additional estimation. Additional uncertainty can thus be introduced at both ends of the spectrum. A simple example illustrates the complications.

If the desired level of data aggregation is a water depth and planning area category $\Gamma_{i,j}$, then because production data is reported at a well level (the "lowest" level possible), the production profiles are readily aggregated to $\Gamma_{i,j}$ without consequence. On the other hand, supply forecasts are usually performed at a "high" level of analysis (normally, on a planning area basis), and hence, to obtain a supply curve over $\Gamma_{i,j}$ it is necessary to decompose the planning area in a water depth categorization and to perform a separate forecast over each water depth category. The introduction of a water depth categorization is not currently compatible with MMS supply forecasting profiles, and so the determination of supply profiles over $\Gamma_{i,j}$ introduces uncertainty within the model that is difficult to quantify.

The time horizon of the forecast also induces additional system constraints. A long-term forecast is commonly required in economic impact studies and logical constraints require that forecasted production profiles do not exceed the estimated resource base. The production profile across each region is thus constrained by the resource estimates in the region. The impact of technological change and the price variability of oil and natural gas are not explicit parameters, but are incorporated indirectly in terms of how fast the resource base is estimated to be recovered. This will be discussed in more detail in Chapter 2.4.2.

2.3.3. Modeling Principles: An infrastructure forecast is developed guided by the following criteria:

- The forecast should be based on a clearly defined structure.
- The forecast should be supported by a set of explicit assumptions.
- The forecast should be performed at a meaningful level of aggregation.
- The model structure and assumptions should be subject to parametric analysis.
- The model should be easy to calibrate and update, and preferably, performed in a step-by-step manner that is easy to understand and modify.
- Uncertainty should be accounted for based on the form of the data and user-defined parameters.
- The process should be transparent and well-documented.
- Short-term and medium-term forecast should be performed separately and calibrated against the long-term forecast.

The philosophy adopted to satisfy these criteria is to maintain simplicity of form and to extrapolate historical experience to predict future trends. To a large extent the current REA model satisfies most of these objectives, but it is deficient in specifying the model uncertainty and allowing user-defined parameters to be incorporated within the procedure. It is for these and other reasons (Lore and Batchelder, 1995) that the REA structure is maintained but structured to ensure a consistent assumption set to allow decision parameters to be applied with scenario analysis. The structural aspects of the proposed model should also help to deflect criticism of the methodology since the results are subject to an explicit assumption set rather than perceived as absolute in nature.

2.3.4. General Methodology: The general methodology is presented in four stages: 1. *Pre-Processing*, 2. *Forecasting*, 3. *Post-Processing*, and 4. *Scenario Analysis*. The stages are described as follows:

1. *Pre-Processing.* Develop historic trends of hydrocarbon production and infrastructure requirements on a water depth and planning area basis $\Gamma_{i,j}$.

   1.1. Report reserves (proved, unproved, appreciation) and resource (undiscovered conventionally recoverable, undiscovered economically recoverable) data over the category $\Gamma_{i,j}$, $R_k(\Gamma_{i,j})$, $k = 1,\ldots, 5$.

1.2. Aggregate historic production profiles for oil and natural gas over $\Gamma_{i,j}$, combine production in terms of a BOE basis, and report a cumulative production profile per category $\Gamma_{i,j}$, $Q(\Gamma_{i,j}, t)$.

1.3. Compute the cumulative number of major (m) and nonmajor (n) structures installed and removed in category $\Gamma_{i,j}$ through time t, $I^{[m,n]}(\Gamma_{i,j}, t)$ and $R^{[m,n]}(\Gamma_{i,j}, t)$.

1.4. Compute the ratio of cumulative structure installation and removal to cumulative production for each classification type per category $\Gamma_{i,j}$, $I^{[m,n]}(\Gamma_{i,j}, t)/Q(\Gamma_{i,j}, t)$ and $R^{[m,n]}(\Gamma_{i,j}, t)/Q(\Gamma_{i,j}, t)$.

2. *Forecasting.* Construct production profiles and determine infrastructure requirements over a θ-year time horizon.

2.1. Forecast hydrocarbon production profiles on a BOE basis to recover p-percent of the resource base $R_T(\Gamma_{i,j}) = R_1(\Gamma_{i,j}) + R_2(\Gamma_{i,j}) + R_3(\Gamma_{i,j}) + R_5(\Gamma_{i,j})$ described in *Step 1.1* over a θ-year horizon, where the parameters (p, θ) are user-defined input.

2.2. Forecast infrastructure requirements for major and nonmajor structures over the category $\Gamma_{i,j}$ based on the extrapolation of the historic ratios computed in *Step 1.4*.

2.3. Forecast the cumulative infrastructure required to recover the anticipated production profiles by multiplying the forecast profiles determined in *Step 2.1* and *Step 2.2*.

3. *Post-Processing.* Determine the annual number of structures installed and removed and the number of active structures per region per structure classification.

3.1. The annual number of structures installed and removed in category $\Gamma_{i,j}$ over the time interval (t-1, t], $i^{[m,n]}(\Gamma_{i,j}, t)$ and $r^{[m,n]}(\Gamma_{i,j}, t)$, is determined through the algebraic relations:

$$i^{[m,n]}(\Gamma_{i,j}, t) = I^{[m,n]}(\Gamma_{i,j}, t) - I^{[m,n]}(\Gamma_{i,j}, t\text{-}1),$$

$$r^{[m,n]}(\Gamma_{i,j}, t) = R^{[m,n]}(\Gamma_{i,j}, t) - R^{[m,n]}(\Gamma_{i,j}, t\text{-}1).$$

3.2. The number of active major and nonmajor structures in category $\Gamma_{i,j}$ in year t, $A^{[m,n]}(\Gamma_{i,j}, t)$, is determined through the dynamic recursion:

$$A^{[m,n]}(\Gamma_{i,j}, t) = A^{[m,n]}(\Gamma_{i,j}, t\text{-}1) + i^{[m,n]}(\Gamma_{i,j}, t) - r^{[m,n]}(\Gamma_{i,j}, t).$$

4. *Scenario Analysis.* Determine the number of structures installed and removed under scenarios that incorporate variation in resource magnitude, development profiles, and technological improvements.

   4.1. The average values of $i^{[m,n]}(\Gamma_{i,j}, t)$ and $r^{[m,n]}(\Gamma_{i,j}, t)$ are assessed over the time horizon θ through resource magnitude and development profile scenarios incorporated through the parameters (p, θ) in *Step 2.1*.

   4.2. The values of $i^{[m,n]}(\Gamma_{i,j}, t)$ and $r^{[m,n]}(\Gamma_{i,j}, t)$ are assessed through technological improvement scenarios by bounding the magnitude of the infrastructure requirements forecast in *Step 2.2*.

2.4. A Decision- and Resource-Based Model

2.4.1. The Infrastructure Forecasting Methodology: The infrastructure forecast methodology proposed is a four-step procedure that is similar in structure to the REA/MMS approach, but differs in the level and type of categorization employed and development of the functionals implemented. To maintain contact with the baseline model, the REA/MMS approach is highlighted in the discussion that follows.

The methodology is described as follows:

Step 1. Construct cumulative hydrocarbon production profiles on a BOE basis per water depth and planning area category over a 40-year time horizon.

Step 2. Forecast the cumulative number of major and nonmajor structures installed and removed per cumulative BOE production on a water depth and planning area basis over a 40-year time horizon.

Step 3. The cumulative number of structures installed and removed over each water depth and planning area category is determined by the product of the profiles determined in *Step 1* and *Step 2*.

Step 4. The annual number of major and nonmajor structures installed and removed are derived from the cumulative forecast in *Step 3*.

The infrastructure forecast is dependent upon the construction of the hydrocarbon production profile (*Step 1*) and forecast of the infrastructure requirements ratio (*Step 2*) across categories specified on a water depth and planning area basis. The hydrocarbon production profile forecast,

$$Q(\Gamma_{i,j}, t)^*,$$

and the infrastructure requirements ratio forecast,

$$\left(\frac{I^{[m,n]}(\Gamma_{i,j}, t)}{Q(\Gamma_{i,j}, t)} \right)^* = \gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*,$$

$$\left(\frac{R^{[m,n]}(\Gamma_{i,j}, t)}{Q(\Gamma_{i,j}, t)} \right)^* = \gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*,$$

represent the key input parameters to the model.

Unfortunately, over a long-term horizon no one knows – or should pretend to know for that matter – the production profile, $Q(\Gamma_{i,j},\ t)^*$, but since this is a required element in all resource-based forecasts, uncertainty should be accounted for in some manner. Uncertainty can be made explicit through the use of decision parameters which allow the user to express in a simple manner their expectations for future production, price, the impact of technological change, etc. The infrastructure requirements ratio forecast, $\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*$ and $\gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*$, is less uncertain due to the integrating nature of the functional. Hence, there is a greater degree of confidence in extrapolating these trends in the future where sufficient data exists to reasonably allow such trending. It is also possible to incorporate a decision parameter in the infrastructure ratio to account for technological change specific to well productivity per platform, but this was not pursued since it can be incorporated within the previous decision parameter.

The product of the functionals

$$Q(\Gamma_{i,j},\ t)^* \cdot \gamma_I^{[m,n]}(\Gamma_{i,j}, t)^* = I^{[m,n]}(\Gamma_{i,j},\ t),$$
$$Q(\Gamma_{i,j},\ t)^* \cdot \gamma_R^{[m,n]}(\Gamma_{i,j}, t)^* = R^{[m,n]}(\Gamma_{i,j},\ t),$$

yields a forecast of the cumulative number of structures installed and removed through time t.

The annual number of structures installed and removed over the time horizon, $i^{[m,n]}(\Gamma_{i,j},\ t)^*$ and $r^{[m,n]}(\Gamma_{i,j},\ t)^*$, is then derived from the cumulative forecast, and the number of active platforms, $A^{[m,n]}(\Gamma_{i,j},\ t)$, is calculated from a recursive relation using the annual installation and removal rates and a boundary condition on the number of active platforms:

$$i^{[m,n]}(\Gamma_{i,j},\ t)^* = I^{[m,n]}(\Gamma_{i,j},\ t)^* - I^{[m,n]}(\Gamma_{i,j},\ t-1)^*,$$

$$r^{[m,n]}(\Gamma_{i,j},\ t)^* = R^{[m,n]}(\Gamma_{i,j},\ t)^* - R^{[m,n]}(\Gamma_{i,j},\ t-1)^*,$$

$$A^{[m,n]}(\Gamma_{i,j},\ t)^* = A^{[m,n]}(\Gamma_{i,j},\ t-1)^* + i^{[m,n]}(\Gamma^*_{i,j},\ t) - r^{[m,n]}(\Gamma_{i,j},\ t)^*.$$

The output functionals, $I^{[m,n]}(\Gamma_{i,j}, t)^*$ and $R^{[m,n]}(\Gamma_{i,j}, t)^*$, are used to compute the annual installation and removal rates using backward recursion. By starting at the end of the time horizon and working through to the present year-by-year, the annual number of installations and removals are calculated. The number of active platforms is then computed using the annual installation and removal rates and the value of $A^{[m,n]}(\Gamma_{i,j}, t-1)^*$.

The uncertainty associated with the output of the model, namely, the uncertainty in the forecasted quantities, $i^{[m,n]}(\Gamma_{i,j}, t)^*$ and $r^{[m,n]}(\Gamma_{i,j}, t)^*$, is bound through the uncertainty associated with the construction of the input functionals and the convolution operations.

2.4.2. The Supply Forecast: A variety of production models can be employed to predict hydrocarbon supply, but it is difficult to ascertain the accuracy of one method relative to another since the specific methodologies must first be duplicated under the assumption set of the models, and then the output must then be compared with data realized in the forecast period. Generally speaking, attention is normally devoted to developing models to replicate historical data as opposed to evaluating the ultimate success/failure of the forecasted results, which is not unusual considering the difficult (some would say impossible) nature of forecasting. An exceptionally good introductory discussion on the limitations of forecasting is provided by Lynch (Lynch, 2002) and is considered required reading. Geophysical, price/regulatory, partial adjustment, discovery, simulation, and hybrid models have all been examined at various times with varying degrees of "success" (Barouch and Kaufman, 1976; Cleveland and Kaufmann, 1991; Eckbo *et al*., 1978; Lore and Batchelder, 1995; MacDonald *et al*., 1994; Moroney and Berg, 1999; Pesaran and Samiei, 1995; Power and Fuller, 1992; Power and Jewkes, 1992; Smith, 1980; Smith and Paddock, 1984; Walls, 1994). Hence, rather than focus on a specific methodology to construct a production profile, it is better to view *all* supply forecasts as highly uncertain with the understanding that some researchers have developed a preference for one methodological technique over another. The MMS constructs production profiles for oil and natural gas using a Hubbert-type model with reserves and resource data provided through the National Assessment (Crawford *et al*., 2000; Lore *et al*., 2001). This technique is one among many alternative methods available and is appealing because of its intuitive nature.

Resource recovery models are characterized by considering resources in terms of a "bundled" unit recoverable within a given time and at a specific rate. In a very real sense this type of assessment is a complete fiction since mineral resources should not be treated as a *fixed* mineral stock, but rather as a *flow* created by investment (Adelman, 1996). Despite the obvious problems and criticism associated with such a model (Lynch, 2002; National Academy of Sciences, 1991), recovering bundled units of resource is justified in terms of its simplicity and the manner in which the forecast is used. Specification of recovery rates and development time leads to the construction of a production path with profile parameters which can incorporate technological change and other variables specified by the user. The simplest resource-based model is to recover the remaining conventionally recoverable resources, $R_T(\Gamma_{i,j})$, according to the *belief* of the decision maker; i.e., the decision maker must address the following question:

What percentage of $R_T(\Gamma_{i,j})$ *will be recovered within the time horizon θ?*

The specification of p and θ is user-defined and accounts for the decision makers understanding of resource recovery, including the nature of technological change, development timing, lease specific conditions, oil price, and supply/demand conditions. It is possible to try to account for these variables in separate models, but this was considered outside the scope of the project. The supply model is referred to as a 2-parameter recovery model since two parameters – p and θ – need to be specified to recover the resource.

The remaining conventionally recoverable resources of region $\Gamma_{i,j}$, $R_T(\Gamma_{i,j})$, represents the volume of all conventionally recoverable resources that has not yet been produced and includes remaining proved reserves $(R_1(\Gamma_{i,j}))$, unproved reserves $(R_2(\Gamma_{i,j}))$, reserves appreciation $(R_3(\Gamma_{i,j}))$, and undiscovered economically recoverable resources $(R_5(\Gamma_{i,j}))$:

$$R_T(\Gamma_{i,j}) = R_1(\Gamma_{i,j}) + R_2(\Gamma_{i,j}) + R_3(\Gamma_{i,j}) + R_5(\Gamma_{i,j}).$$

For a detailed definition of each resource category, see (Crawford *et al*., 2000; Lore *et al*., 2001; Society of Petroleum Engineers and World Petroleum Congress, 1997) and for the current National Assessment estimates, refer to Table B.2. Attanasi (Attanasi, 2001) provides one alternative perspective the reader may wish to consult. The value of $R_T(\Gamma_{i,j})$ is bound by a high (optimistic) and low (pessimistic) estimate, referred to as F5 (5th percentile) and F95 (95th percentile), respectively. The F5 estimate[12] reflects the resource quantity having a 5-percent probability that the ultimate resource, when found, will equal or exceed the estimated quantity. Similarly, the F95 estimate reflects the resource quantity having a 95-percent probability (19 in 20 likelihood) that the ultimate resource will equal or exceed the estimate.

The decision variables of the resource recovery model are denoted by (p, θ), $0 \le p \le 1$, where $100p$ designates the percentage of the resource recovered within the time horizon θ. The region of aggregation, $\Gamma_{i,j}$, and resource quantity, $R_T(\Gamma_{i,j})$, is assumed given, and the time horizon of the forecast is assumed to be θ years from the current time τ. The system variables are denoted as:

Input: $0 < p \le 1$, θ and $R_T(\Gamma_{i,j})$

Output: $Q(\Gamma_{i,j}, t)^*$,

and the procedure to construct the supply forecast is described as follows:

[12] The F5 and F95 estimates represent the mean economically recoverable resources using an optimistic ($30/bbl oil, $3.52/Mcf gas) and pessimistic ($18/bbl oil, $2.11/Mcf gas) scenario.

Step 1. Plot the historic cumulative production curve $Q_h(\Gamma_{i,j}, t)$, $t \le \tau$.

Step 2. The cumulative production forecast $Q_h(\Gamma_{i,j}, t)^*$, $t > \tau$, is extrapolated in a linear fashion to recover 100p-percentage of $R_T = R_T(\Gamma_{i,j})$ within θ years, and all the resources within the 40-year time horizon. The cumulative production curve is written analytically as

$$Q(\Gamma_{i,j},t)^* = \begin{cases} Q_h(\Gamma_{i,j},t), & t \le \tau \\ \dfrac{pR_T}{\theta}(t-\tau) + Q_h(\Gamma_{i,j},t), & \tau \le t \le \tau+\theta \\ \dfrac{(1-p)pR_T}{40-\theta}(t-\tau-\theta) + pR_T + Q_h(\Gamma_{i,j},t), & \tau+\theta \le t \le \tau+40. \end{cases}$$

The value of $R_T = R_T(\Gamma_{i,j})$ can be selected as the F5, F50, or F95 estimate. The model is simple to use, which is its main attraction, and one can argue that the uncertainty involved with estimating future production profiles and the impact of technological change is such that structurally simple models capture the essence of the forecast in a manner analogous to more sophisticated models. Through the selection of p and θ the user can dictate a wide variety of scenarios that reflect trends and technological conditions within specific regions of the GOM.

2.4.3. The Infrastructure Ratio Forecast: The MMS approach requires three forecast to predict platform installation and removal rates:

- $q(\Gamma_{i,j}, t)^*$
- $\left(\dfrac{q(\Gamma_{i,j},t)}{A(\Gamma_{i,j},t)}\right)^*$, and
- $i(\Gamma_{i,j}, t)^* : r(\Gamma_{i,j}, t)^*$.

The CES approach also requires three forecast:

- $Q(\Gamma_{i,j}, t)^*$
- $\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*$, and
- $\gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*$.

The MMS application of the annual production forecast $q(\Gamma_{i,j}, t)^*$ and infrastructure forecast ratios $\left(\frac{q(\Gamma_{i,j},t)}{A(\Gamma_{i,j},t)}\right)^*$ motivated the CES application of cumulative production $Q(\Gamma_{i,j}, t)^*$ and the ratios $\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*$ and $\gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*$. In the MMS approach, however, another forecast is required to translate the number of active platforms to annual installation and removal rates, while in the CES approach application of the cumulative infrastructure ratio eliminates the need to forecast the installation and removal ratio. The CES methodology incorporates expert judgment in the determination of $Q(\Gamma_{i,j}, t)^*$, and although it is not difficult to structure the procedure to allow user-defined input on the selection of the ratio forecast, $\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*$ and $\gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*$, the current methodology does not develop this approach. The MMS employs expert judgment to determine the infrastructure forecast ratio, and while there are some benefits for a decision maker to provide such input, there are also disadvantages since the inclusion of too many parameters can confound the analysis.

The forecast $\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^*$ and $\gamma_R^{[m,n]}(\Gamma_{i,j}, t)^*$ are based on linear extrapolation of historic data within category $\Gamma_{i,j}$, and in the event that the category $\Gamma_{i,j}$ does not have sufficient data on which to base a trend, a constant value is assumed based on the ratio at the current time τ; i.e., $\gamma_I^m(\Gamma_{i,j}, t)^* = \gamma_I^m(\Gamma_{i,j}, \tau)$ for $t \geq \tau$.

<u>2.4.4. Model Results and Interpretation:</u> After the historic data on offshore structures has been categorized according to water depth, planning area, and configuration type, and after the appropriate resource data has been compiled and tabulated, it is then a matter of providing a forecast for

$$Q(\Gamma_{i,j}, t)^*,$$

and

$$\gamma_I^{[m,n]}(\Gamma_{i,j}, t)^* = \left(\frac{I^{[m,n]}(\Gamma_{i,j}, t)}{Q(\Gamma_{i,j}, t)}\right)^*, \quad \gamma_R^{[m,n]}(\Gamma_{i,j}, t)^* = \left(\frac{R^{[m,n]}(\Gamma_{i,j}, t)}{Q(\Gamma_{i,j}, t)}\right)^*,$$

to drive the model output. The form of the supply forecast is tied to the decision maker, in the selection of the parameter values p and θ, while the infrastructure forecast is automated based on linear extrapolation. The product of the functionals yields the cumulative number of installed and removed structures which is then processed to determine the annual installation and removal rates for the major and nonmajor categories.

The forecast of the average annual number of major and nonmajor structures installed and removed in the CGOM and WGOM is provided in Tables B.3 and Tables B.4. The annual installation and removal rates over the time horizon of the forecast are reported in terms of an annual average rate over θ which is denoted by

$$\langle i^{[m,n]}(\Gamma_{i,j}, t)^* \rangle$$

$$\langle r^{[m,n]}(\Gamma_{i,j}, t)^* \rangle .$$

Average annual rates are normally non-integer, so that for instance if $\langle i^{[m,n]}(\Gamma_{i,j}, t)^* \rangle$ = 0.5, then one nonmajor structure will be installed in $\Gamma_{i,j}$ every two years.

To interpret the model output, the user selects the time frame and resource recovery parameters that he/she believes will reflect the nature of resource recovery, supply/demand conditions, and technological change in the future. For instance, if 75% of the hydrocarbon resources within 0-200m in the CGOM are believed to be recoverable by 2020, then from Table B.3.2 with p = 0.75 the average annual number of major and nonmajor structure installations are (10.9, 56.3) with (54.5, 95.3) annual major and nonmajor structure removals. The decision maker may have reason to assess the 201-800m and 800+ m categories on a different time horizon and recovery rate; e.g., if 50% of the resources within the deepwater categories are believed to be recoverable through 2030, then from Table B.3.3 with p = 0.50 an expected (1.3, 0.2) major and nonmajor structure installations are expected in 201-800m and (3.1, 1.5) installations are expected within 800+ m. No major or nonmajor structures are expected to be removed during this time.

The annualized forecast values in Tables B.3 and Tables B.4 can be compared against the average short-term historic installation and removal rates shown in Table B.5. For example, using Table B.3.1 and the short-term historic average values shown in Table B.5, the model forecast can be calibrated by comparing the 0-200m values for major and nonmajor installations and removals, (32, 78) and (37, 69), respectively, with the closest approximation in Table B.3.1. In this case the installation rate corresponds to $p \approx 0.5$ while the removal rate corresponds to $p \approx 0.25$.

In principle, the tables can be used one of two ways:

I. The user determines the values of p and θ per water depth and planning area category, $\Gamma_{i,j}$, and then employs the table to forecast expected average installation and removal rates, $\langle i^{[m,n]}(\Gamma_{i,j}, t) \rangle$ and $\langle r^{[m,n]}(\Gamma_{i,j}, t) \rangle$.

II. The user specifies the expected average installation and removal rates per category $\Gamma_{i,j}$, $\langle i^{[m,n]}(\Gamma_{i,j}, t)^* \rangle$ and $\langle r^{[m,n]}(\Gamma_{i,j}, t)^* \rangle$, and then using the table, determines the value of p and θ that correspond to these rates.

The selection of p and θ is considered independent across water depth categories.

The results of the model reveal expected behavior. For instance, recovering a greater percentage of the available resources within a short time horizon (should) impose greater infrastructure requirements; i.e., if a data entry in the table is denoted by $f(\Gamma_{i,j}, p, \theta)$, then

$$f(\Gamma_{i,j}, p, \theta) \leq f(\Gamma_{i,j}, p, \theta') \text{ if } \theta' > \theta,$$

$$f(\Gamma_{i,j}, p, \theta) \leq f(\Gamma_{i,j}, p', \theta) \text{ if } p' > p.$$

2.5. Limitations of the Analysis

A number of issues in Chapter 2 warrant a more careful treatment. The main issues are as follows.

(1) Decoupling Installation and Removal Methodologies

The majority of structures that will be removed in the GOM over the next 25 years are primarily the structures that are currently active. Structures that are expected to be removed in the late future (25 years hence) will be primarily drawn from structures *to be* installed in the future. It is thus desirable to decouple the installation and removal models and to develop separate models for installation and removal. While structure installations over a long-term horizon are naturally developed with the framework described in this paper, a variety of structure removal models (life expectancy, simulation, production-based) are considered superior to the model described herein because they can explicitly take into account the operating environment, geologic conditions, and structure characteristics.

(2) Structure Classification

There are a number of ways in which structures can be classified and further investigation of categorization schemes is warranted. Classifying structures within "major" and "nonmajor" categories was performed to differentiate heterogeneous structures, but further refinement of the methodology which classifies structures according to configuration type (caisson, well-protector, fixed, floating) can also be pursued.

(3) Supply Forecast Models

Forecasting hydrocarbon supply profiles is considered a problem in *any* modeling environment regardless of the application since forecasting oil prices and consumption levels is not an endeavor that can ever be done particularly well. The supply forecast is a highly uncertain quantity that depends largely on the assumptions and preferences of the user or organization performing the forecast. It is necessary to perform a supply forecast across region $\Gamma_{i,j}$ since the resource assessment and the infrastructure statistics are aggregated at this level, but if the user is not experienced or comfortable performing supply profiles at this level, then a re-assessment of the methodology may be required. Production profiles based on a 2-parameter decision model were employed to construct the supply forecast. The supply model implicitly incorporates technological change and other exogeneous variables within the user-defined parameters, but if an econometric model were to be developed, it would be desirable to account for these variables directly. The benefits of applying discovery models over low aggregation levels versus the additional complexity and uncertainty of such models needs to be evaluated.

(4) Infrastructure Requirement Ratio Forecast

A variety of techniques can be employed to forecast infrastructure requirements, and it is difficult to gauge the accuracy of one technique over another. It is therefore essential that the user of a particular approach understand the limitations and implicit assumptions of the model and uncertainty inherent to the methodology. Scenario analysis is a useful tool to explore some of this uncertainty as proposed in the 2-parameter supply model, and it may be desirable to incorporate additional decision parameters to control the infrastructure ratio forecast.

(5) Application of BOE

A barrel of oil has about 5.6 times the heat value of one thousand cubic feet of gas, and so it is popular to express gas in terms of barrels of "oil equivalent." This was necessary in the forecast model since both oil and gas contribute to the need for infrastructure. Unfortunately, since neither the price nor the in-ground value of oil and gas track each other, and in fact are constantly in flux depending on inventory levels, fuel prices and other market conditions, the application of BOE is less desirable than the use of separate oil and gas accounting standards in resource estimates and forecast modeling.

(6) Oil and Gas Wells

After a well is drilled it is either classified as an "oil" well or a "gas" well depending on the value of the gas-oil ratio. Since a collection of wells is typically associated with a given structure, it is possible to classify a structure as an "oil" or "gas" structure and then to perform the infrastructure forecast at this level of aggregation. One advantage of this approach is that it would allow separate oil and gas production profiles to drive the forecast which would allow the nature of oil and gas production and their infrastructure requirements to be better understood. Unassociated gas wells have significantly different productive lifetimes (usually shorter) than oil and associated gas wells, and so there is good reason to pursue a disaggregated forecast in this manner.

(7) Forecast Time Horizons

Infrastructure forecasting can be considered across three time horizons: the short-term (1-5 years), the medium-term (6-20 years), and the long-term (21-40 years). Each time horizon should be considered separately and the best forecast model applied to each category. The short-term installation and removal forecast can be developed using historic trends. The medium-term removal forecast can be developed using life-expectancy and/or economic limit models, and for the installation forecast, discovery models. A long-term forecast can employ a decision and resource framework. The short-term and medium-term forecast should also be calibrated against the long-term forecast.

2.6. Conclusions

The task of Chapter 2 was to develop a unified approach to infrastructure forecasting in the Gulf of Mexico and to forecast the number of structures expected to be installed and removed per water depth and planning area category over a long-term horizon. The consistency of the methodology, the application of a discrete assumption set, and the inclusion of a decision-oriented framework within the model represent the central tenants of the procedure. The model results should be interpreted as a first-order approximation to a very complex reality, and as such, should serve as a guide to infrastructure forecast requirements.

The need to properly select and specify aggregation categories is a critical ingredient in any forecast strategy, and the decomposition of the data into appropriate categories is an important aspect of pre-processing to ensure that the methodology is consistent and the procedure is sufficiently structured. No matter how fine the infrastructure data is decomposed and disaggregated within various categories, however, the forecasting procedures employed in Chapter 2 rely upon other forecast and judgmental adjustments which can differ enormously in scope and magnitude. The uncertainty in these adjustments should be understood and clearly communicated to the user group. One of the principal tasks of this Chapter was to identify this uncertainty and to employ decision-oriented parameters as a means to explore the sensitivity of the model results.

The infrastructure forecast developed is a decision- and resource-based model similar to the methodology employed by the MMS but more broadly defined and executed within an analytic and computational framework. The output of the model is derived from the forecast of a supply curve and an infrastructure requirement ratio. A decision-oriented framework is employed to construct the supply curve which incorporates the beliefs of the user and variables such as technology change. The results of the forecast were presented under various assumptions on recovery rate and development timing.

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APPENDIX A
CHAPTER 1 TABLES

Table A.1

Western and Central GOM National Assessment Resource Estimates and REA/MMS Allocation Quantities

Category[2]	Notation[3, 4]	Western Gulf of Mexico					
		National Assessment[1,5]		MMS Allocation[6]		Percent Recovery[7]	
		Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (%)	Gas (%)
	Q_h	0.559	23.800	0.557	23.4	100	100
	R_1	0.495	7.393				
	R_2	0.067	0.603				
	R_3	1.091	17.881				
K_1	$R_1+R_2+R_3$	1.653	25.877	(1.37, 1.669)	(24.88, 26.6)	(83, 101)	(96, 103)
	R_4	(12.11, 14.22)	(70.19, 80.36)				
K_2	R_5	(6.46, 9.87)	(38.49, 54.10)	(1.98, 3.47)	(17.7,31.6)	(31, 35)	(46, 58)
Total (K_1+K_2)	R_T	(8.11, 11.52)	(64.37, 79.98)	(3.35, 5.14)	(42.6,58.2)	(41, 45)	(66, 73)
		Central Gulf of Mexico					
		National Assessment		MMS Allocation		Percent Recovery[6]	
	Q_h	10.4	108.9	10.36	109.3	100	100
	R_1	2.9	22.6				
	R_2	0.9	3.8				
	R_3	6.6	49.6				
K_1	$R_1+R_2+R_3$	10.4	76	(8.15, 8.26)	(74.4, 76.0)	(78, 79)	(98, 100)
	R_4	(18.5, 23.8)	(99.4, 114.0)				
K_2	R_5	(9.51, 15.37)	(54.73, 77.47)	(3.90, 8.30)	(33.90, 70.3)	(41, 54)	(62, 91)
Total (K_1+K_2)	R_T	(19.91, 25.77)	(130.73,153.47)	(12.05, 16.56)	(108.3,146.3)	(61, 64)	(83, 95)

Footnote:

(1) The National Assessment data is current as of January 1, 1999, and the MMS data is adjusted to correspond to this date; i.e., the cumulative production represented by Q_h is taken through the year 1998.
(2) Resource category K_1 denotes assessed reserves and appreciation. Resource category K_2 denotes assessed undiscovered economic resources.
(3) The resource estimates are designated as remaining proved reserves R_1 unproved reserves R_2, reserves appreciation R_3, undiscovered conventionally recoverable resources R_4, and undiscovered economically recoverable resources R_5. R_T denotes the remaining conventionally recoverable resources: $R_T = R_1+ R_2+ R_3+ R_5$.
(4) Undiscovered economically recoverable resources R_5 are evaluated at the mean of the price-supply curves at \$18/bbl and \$30/bbl oil.
(5) The National Assessment of the resource estimates R_4 are provided at the 95th and 5th percentile scenario, (F95, F5).
(6) The MMS allocation levels for R_1 are provided as “low” and “high” estimates, while the allocation levels for R_5 and R_T correspond to mean levels.
(7) The percent recovery is defined as the MMS allocation divided by the National Assessment estimates: $p = Q(P_i)/ R_j(P_i)$.

Table A.2

A Summary of Measures Implied by the REA/MMS Forecast

Measure	WGOM	CGOM	GOM[3]
Total Resource Recovery[1]			
Oil	(41%, 44%)	(59%, 64%)	(54%, 58%)
Gas	(67%, 73%)	(83%, 95%)	(77%, 88%)
BOE	(55%, 60%)	(72%, 75%)	(61%, 73%)
Implied Recovery[1]			
Oil	(63%, 50%)	(65%, 73%)	(64%, 73%)
Gas	(57%, 52%)	(77%, 93%)	(64%, 81%)
BOE	(59%, 51%)	(72%, 85%)	(64%, 73%)

Footnote:

(1) The total resource recovery percentage is defined as the MMS allocation divided by the National Assessment estimates. The values are summarized from Table A.1.
(2) Implied recovery is determined by plotting the cumulative production profile and then computing how much of the resource estimate is recovered θ years from the present time, where for convenience, θ is selected as 20 years. The National Assessment estimates and MMS allocation are given under a (low, high) case scenario and are computed with respect to this classification. Note that (x, y) does not necessarily require $x<y$ since the low and high case calculations are independent estimates of resource and recovery rates.
(3) The Gulf of Mexico resource estimates include only the Western and Central planning areas.

APPENDIX B
CHAPTER 2 TABLES

Table B.1

Offshore Statistics by Water Depth

Water Depth (m)	Active Platforms	Production Wells	Producing Well / Active Platform
0-200	3,489	3,840	1.1
201-400	455	1,873	4.1
401-800	49	285	5.8
801-1000	4	50	12.5
1000+	22	309	14.0

Table B.2

National Assessment Results for the Western and Central Planning Area in the Gulf of Mexico, BOE (Bbbl)

Water Depth (m)	R_1 [a]	R_2	R_3	R_4 [b]		R_5		R_T	
				F95	F5	F95	F5	F95	F5
Western									
0-200	1.16	0.00	2.72	4.32	5.43	3.12	3.63	7.00	7.51
201-800	0.23	0.02	0.43	3.37	4.47	2.94	3.24	3.62	3.92
801-1600	0.42	0.15	1.12	7.57	9.42	4.76	6.73	6.45	8.42
1601-2400	0.00	0.00	0.00	6.54	8.38	1.99	4.66	1.99	4.66
2400+	0.00	0.00	0.00	1.73	2.65	0.54	1.29	0.54	1.29
Total [c]	1.81	0.17	4.27	24.60	28.52	13.31	19.50	19.56	25.75
Central									
0-200	4.30	0.11	8.51	6.89	8.21	5.13	6.00	18.05	18.92
201-800	1.18	0.14	1.69	3.23	4.26	3.24	3.56	6.25	6.57
801-1600	1.28	0.58	2.98	10.31	12.84	6.70	9.50	11.54	14.34
1601-2400	0.13	0.79	2.29	11.27	15.07	3.36	7.91	6.57	11.12
2400+	0.00	0.00	0.00	3.00	7.02	0.89	2.34	0.89	2.34
Total [c]	6.89	1.62	15.47	36.15	44.04	19.25	29.15	43.23	53.13

Source: (Lore *et* al., 1999)

Footnote: (a) The resource estimates are designated as remaining proved reserves (R_1), unproved reserves (R_2), reserves appreciation (R_3), undiscovered conventionally recoverable resources (R_4), and undiscovered economically recoverable resources (R_5). R_T denotes the remaining conventionally recoverable resources: $R_T = R_1 + R_2 + R_3 + R_4$.

(b) F95 represents the mean economically recoverable resources at $30/bbl ($3.52/Mcf). F5 represents the mean economically recoverable resources at $18/bbl ($2.11/Mcf).

(c) Summation of individual resource values may differ from total values due to independent computer runs and rounding.

Table B.3.1

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the CGOM Through 2010 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	12.5	35.1	42.9	74.0
	0.50	32.3	81.2	56.1	100.4
	0.75	61.8	127.3	69.2	126.9
	1.00	91.5	173.4	82.4	153.3
201-800	0.25	1.9	0.4	0.1	-
	0.50	3.9	0.7	0.3	-
	0.75	5.8	1.1	0.4	-
	1.00	7.7	1.4	0.5	-
800+	0.25	4.6	2.3	-	-
	0.50	9.2	4.6	-	-
	0.75	13.8	6.9	-	-
	1.00	18.3	9.2	-	-

Table B.3.2

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the CGOM Through 2020 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	4.2	11.8	37.1	62.1
	0.50	5.7	34.1	45.8	78.7
	0.75	10.9	56.3	54.5	95.3
	1.00	23.6	78.6	63.3	112.0
201-800	0.25	1.0	0.2	0.1	-
	0.50	1.9	0.4	0.1	-
	0.75	2.9	0.5	0.2	-
	1.00	3.9	0.7	0.2	-
800+	0.25	2.3	2.3	-	-
	0.50	4.6	4.6	-	-
	0.75	6.9	6.9	-	-
	1.00	9.2	9.1	-	-

Table B.3.3

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the CGOM Through 2030 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	1.1	4.0	35.2	58.1
	0.50	1.4	18.3	42.4	71.4
	0.75	2.5	32.7	49.6	84.8
	1.00	6.1	47.0	56.9	98.1
201-800	0.25	0.6	0.1	-	-
	0.50	1.3	0.2	0.1	-
	0.75	1.9	0.4	0.1	-
	1.00	2.6	0.5	0.2	-
800+	0.25	1.5	0.8	-	-
	0.50	3.1	1.5	-	-
	0.75	4.6	2.3	-	-
	1.00	6.1	3.1	-	-

Table B.3.4

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the CGOM Through 2040 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	0.2	0.2	34.2	56.1
	0.50	0.2	10.5	40.7	67.8
	0.75	0.6	20.8	47.2	79.5
	1.00	1.5	31.2	53.7	91.2
201-800	0.25	0.5	0.1	-	-
	0.50	1.0	0.2	0.1	-
	0.75	1.4	0.3	0.1	-
	1.00	1.9	0.4	0.1	-
800+	0.25	1.1	0.6	-	-
	0.50	2.3	1.1	-	-
	0.75	3.4	1.7	-	-
	1.00	4.6	2.3	-	-

Table B.4.1

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the WGOM Through 2010 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	8.2	11.7	15.7	17.1
	0.50	11.8	24.8	23.7	26.2
	0.75	23.8	37.9	31.7	35.3
	1.00	35.7	51.1	39.7	44.4
201-800	0.25	3.0	0.8	0.3	0.3
	0.50	6.1	1.7	0.6	0.6
	0.75	9.1	2.5	0.8	0.8
	1.00	12.2	3.3	1.1	1.1
800+	0.25	1.2	1.1	-	-
	0.50	2.5	2.4	-	-
	0.75	3.7	3.7	-	-
	1.00	4.9	4.9	-	-

Table B.4.2

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the WGOM Through 2020 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	5.7	4.9	12.8	13.7
	0.50	10.2	11.2	18.2	19.7
	0.75	17.1	17.5	23.6	25.7
	1.00	22.2	23.8	29.0	31.8
201-800	0.25	1.5	0.4	0.1	0.1
	0.50	3.0	0.8	0.3	0.3
	0.75	4.6	1.2	0.4	0.4
	1.00	6.1	1.7	0.6	0.6
800+	0.25	0.6	0.6	-	-
	0.50	1.2	1.2	-	-
	0.75	1.8	1.8	-	-
	1.00	2.5	2.5	-	-

Table B.4.3

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the WGOM Through 2030 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	3.2	2.7	11.8	12.5
	0.50	8.8	6.7	16.3	17.5
	0.75	14.7	10.7	20.9	22.5
	1.00	17.3	14.7	25.4	27.6
201-800	0.25	1.0	0.3	0.1	0.1
	0.50	2.0	0.6	0.2	0.2
	0.75	3.0	0.8	0.3	0.3
	1.00	4.1	1.1	0.4	0.4
800+	0.25	0.4	0.4	-	-
	0.50	0.8	0.8	-	-
	0.75	1.2	1.2	-	-
	1.00	1.6	1.6	-	-

Table B.4.4

Forecast of the Annual Number of Major and Nonmajor Structures Installed and Removed in the WGOM Through 2040 as a Function of Water Depth and Supply Curve Parameter *p*

Water Depth (m)	*p*	Major Installed	Nonmajor Installed	Major Removed	Nonmajor Removed
0-200	0.25	1.1	1.5	11.3	11.9
	0.50	5.4	4.4	15.4	16.5
	0.75	10.1	7.3	19.5	20.9
	1.00	14.4	10.2	23.7	25.4
201-800	0.25	0.8	0.2	0.1	0.1
	0.50	1.5	0.4	0.1	0.1
	0.75	2.3	0.6	0.2	0.2
	1.00	3.0	0.8	0.3	0.3
800+	0.25	0.3	0.3	-	-
	0.50	0.6	0.6	-	-
	0.75	0.9	0.9	-	-
	1.00	1.2	1.2	-	-

Table B.5

The Average Annual Number of Major and Nonmajor Structures Installed and Removed in the Western and Central Gulf of Mexico via Water Depth Category (1996-2000)

Water Depth	Major Structures		Nonmajor Structures		All Structures	
(m)	Installed	Removed	Installed	Removed	Installed	Removed
Western						
0-60	(5, 3.9)	(9.2, 3.3)	(13, 3.1)	(11.4, 6.4)	(18, 5.2)	(20.6, 7.1)
61-200	(2, 0.7)	(1.2, 0.8)	(1.6, 1.1)	(0.2, 0.5)	(3.6, 5.1)	(1.4, 1.1)
0-200	(7, 4.5)	(10.4, 3.1)	(14.6, 3.2)	(11.6, 6.1)	(21.6, 6.2)	(22, 6.4)
201-800	(0.6, 0.9)	(0.2, 0.5)	(0.6, 0.6)	(0.2, 0.5)	(1.2, 0.5)	(0.4, 0.6)
800+	(0, 0)	(0, 0)	(0.2, 0.5)	(0, 0)	(0.2, 0.5)	(0, 0)
Total	(7.6, 4.0)	(10.6, 2.9)	(15.4, 3.2)	(11.8, 5.4)	(23.0, 5.8)	(22.4, 6.2)
Central						
0-60	(22.8, 14.7)	(31.8, 12.3)	(70.2, 16.8)	(67.8, 22.2)	(93.0, 22.4)	(99.6, 31.8)
61-200	(9, 7.5)	(5.6, 2.6)	(7.4, 4.2)	(0.8, 0.8)	(16.4, 4.6)	(6.4, 3.1)
0-200	(31.8, 20.7)	(37.4, 13.9)	(77.6, 17.2)	(68.6, 22.1)	(109.4, 23.2)	(106.0, 33.9)
201-800	(1.2, 1.6)	(0, 0)	(0.2, 0.5)	(0, 0)	(1.4, 1.5)	(0, 0)
800+	(0.8, 0.5)	(0, 0)	(0.4, 0.6)	(0, 0)	(1.2, 0.8)	(0, 0)
Total	(33.8, 20.4)	(37.4, 13.1)	(78.2, 16.5)	(68.6, 20.8)	(112.0, 21.7)	(106.0, 32.0)
GOM						
0-60	(27.8, 17.3)	(41.0, 14.5)	(83.4, 15.8)	(79.2, 24.9)	(111.2, 24.0)	(120.2, 35.2)
61-200	(11, 8)	(6.8, 2.3)	(9, 4)	(1, 1.2)	(20, 6)	(7.8, 3.2)
0-200	(38.8, 24.2)	(47.8, 15.9)	(92.4, 14.9)	(80.2, 24.6)	(131.2, 25.2)	(128.0, 36.7)
201-800	(1.8, 2.4)	(0.2, 0.5)	(0.8, 0.8)	(0.2, 0.5)	(2.6, 1.9)	(0.4, 0.6)
800+	(0.8, 0.5)	(0, 0)	(0.6, 0.9)	(0, 0)	(1.4, 1.1)	(0, 0)
Total	(41.4, 23.7)	(48.0, 14.9)	(93.8, 13.8)	(80.4, 23.2)	(135.2, 23.4)	(128.4, 34.7)

Footnote: The data entries are denoted (μ, σ), where μ is the average and σ is the standard deviation of the category data.

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.