OCS Study
BOEM 2020-032

Cumulative Impacts Model and Lifecycle Impacts Model for Assessing Economic and Fiscal Impacts of Offshore Oil and Gas Activities

U.S. Department of the Interior
Bureau of Ocean Energy Management
New Orleans Office

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Cumulative Impacts Model and Lifecycle Impacts Model for Assessing Economic and Fiscal Impacts of Offshore Oil and Gas Activities

Authors

Jason C. Price
Mark Ewen
Henrik Isom
Jacob Ebersole
Jacob Lehr

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Industrial Economics, Inc.
2067 Massachusetts Ave.
Cambridge, MA 02140

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Abbreviations and Acronyms

Short Form	Long Form
AEO	Annual Energy Outlook
BEA	Bureau of Economic Analysis
BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
CBO	Congressional Budget Office
CCA	capital consumption allowance
CIM	Cumulative Impacts Model
DD&A	depreciation, depletion, and amortization
DOI	Department of the Interior
E&D	exploration and development
EIA	Energy Information Administration
EIAs	economic impact areas
FRS	financial reporting system
G&G	geological and geophysical
GOM	Gulf of Mexico
GOMESA	Gulf of Mexico Energy Security Act
HPF	Historic Preservation Fund
IADC	International Association of Drilling Contractors
IRS	Internal Revenue Service
LCIM	Lifecycle Impacts Model
LWCF	Land and Water Conservation Fund
NEMS	National Energy Modeling System
NEV	net economic value
NIIT	net investment income tax
NIPAs	National Income and Product Accounts
O&G	oil and gas
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
ONRR	Office of Natural Resources Revenue
QOCSR	Qualified OCS Revenues
RMA	risk management association
RPC	Regional Purchase Coefficient
SEC	Securities and Exchange Commission
WTI	West Texas Intermediate

1 Introduction

The Bureau of Ocean Energy Management (BOEM) is charged with assisting the US Secretary of the Interior in carrying out the mandates of the Outer Continental Shelf (OCS) Lands Act (OCSLA), which calls for expedited exploration and development of the OCS to "achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources and maintain a favorable balance of payments in world trade." To assess the extent to which its activities support these objectives, BOEM regularly conducts economic and/or socio-economic assessments of the value of OCS oil and gas resources and of the effects of auctioning the rights to explore for and develop those resources. For example, when preparing a new National OCS Oil and Gas Leasing Program (required at least every five years), BOEM assesses the potential effects on output and employment of the activities associated with each proposed five-year schedule of sales that the Secretary considers during that multi-year process. Since 2010, BOEM has also developed annual estimates of the economic contributions of OCS oil and gas activity for inclusion in the Department of the Interior's (DOI) Economic Report series. In addition, when BOEM receives bids from prospective lessees, BOEM performs assessments of bid adequacy to ensure that the federal government receives fair market value for the lease rights granted and minerals conveyed. An important aspect of these assessments is an evaluation of the financial viability of a bid, which involves the development of a discounted cash flow analysis to estimate various measures of bid adequacy.[1]

To enhance its capacity for assessing the economic and fiscal impacts of OCS oil and gas activities in the Gulf of Mexico OCS region, BOEM developed the Cumulative Impacts Model (CIM) and the Lifecycle Impacts Model (LCIM), both of which build upon previous economic and financial analysis frameworks developed by BOEM.[2] The CIM estimates the economic and fiscal impacts of all OCS oil and gas activity occurring in the Gulf of Mexico (Gulf) for the time period analyzed, which may be a recent historical year or a forecast period of up to 15 years. In contrast, the LCIM estimates the economic impacts and various metrics of financial viability associated with an individual lease or group of leases over their entire life cycle. The economic impacts estimated by the two models include the output, value added, income, and employment associated with OCS oil and gas activity. The estimates of these impacts reflect direct impacts realized by the offshore oil and gas industry, as well as spillover effects to other industries. Complementing their estimates of economic impacts, the CIM and LCIM also calculate the revenues received by federal, state, and local governments due to OCS oil and gas activities. Such revenues include taxes collected by the federal government and the states, as well as royalties, rents, and bonus bids collected by BOEM, a portion of which the Department of the Interior (DOI) must distribute to state and local governments. The two models estimate these economic and fiscal impacts at the national, state, and sub-state level. In addition to these metrics of economic activity, the LCIM (but not the CIM) estimates several metrics of financial viability for a lease or group of leases, including net present value (NPV) of profits and the payback period.

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[1] These measures of bid adequacy include a tract's Mean Range of Values, Delayed Mean Range of Values, and Adjusted Delayed Value. See BOEM (2016).

[2] In the context of the CIM and LCIM, economic impacts refer to the changes in output, value added, employment, and income associated with OCS oil and gas exploration and development. These impacts reflect activity for industries directly involved in OCS oil and gas exploration and development, as well as spillover effects to other industries. Fiscal impacts refer to the government revenues generated due to OCS oil and gas activity, as well as the changes in output, value added, employment, and income associated with the expenditure of these revenues.

1.1 CIM Overview

Figure 1 summarizes the overall structure of the CIM. As the figure indicates, the CIM estimates economic and fiscal impacts associated with (1) offshore oil and gas industry expenditures, (2) industry profits, and (3) OCS government revenues (i.e., royalties, bonus bids, and rents). The CIM's impact estimates related to industry expenditures reflect the overall level of OCS oil and gas activity (e.g., number of exploration wells drilled), the cost of individual activities, and the magnitude of the economic spillover effects associated with each activity. With respect to profit-related effects, the model estimates government revenues associated with taxes on both corporate profits and dividend payments, as well as economic impacts associated with the spending of tax revenues and dividend income. Similarly, the CIM's estimates of impacts related to OCS revenues include disbursements of OCS revenues to different jurisdictions and the economic impacts associated with government agencies (federal, state, and local) spending these revenues.

The CIM estimates the economic and fiscal impacts of OCS oil and gas activity in the Gulf with a significant degree of spatial detail. For the states in the Gulf region, the model estimates impacts for a series of 23 distinct economic impact areas (EIAs) that collectively include 133 counties and parishes on or near the Gulf coast. These EIAs, shown in Figure 2, represent collections of counties and parishes that BOEM considers most likely to be affected by oil and gas operations in the Gulf. BOEM defined the borders of these EIAs based on detailed analysis of labor market commuting patterns, trade patterns for goods and services, trade patterns for the oil and gas industry, and demographic patterns (Varnado and Fannin 2018). Each EIA contains between two and 13 counties (parishes), with an average of 5.8 counties per EIA. None of the EIAs cross state boundaries. In addition to estimating impacts for individual EIAs, the CIM also estimates impacts for each rest-of-state area in the Gulf region (i.e., the area in each Gulf state not included in an EIA) and for each individual state outside the Gulf region.

To estimate the economic impacts associated with industry expenditures, government spending, and household spending, the CIM applies economic multipliers obtained from the 2017 version of the IMPLAN input-output model (IMPLAN 2017). Input-output models represent a well-established set of tools designed to assess the economic impacts associated with a change in expenditures for one or several industries across multiple sectors of the economy. Using detailed data on inter-industry relationships, input-output models estimate how a positive or negative shock in one industry (e.g., a change in output) cascades across the broader economy. Thus, in addition to capturing direct economic impacts for industries with increased (or decreased) production, input-output models capture spillover effects to other industries. These spillover effects include indirect impacts and induced impacts. Indirect impacts reflect inter-industry purchases and arise from firms purchasing inputs from their suppliers, while induced impacts result from wages paid to workers, who may spend these wages on consumer electronics, clothing, etc. The multipliers obtained from IMPLAN and other input-output models reflect these effects.

In addition to IMPLAN multipliers, the CIM relies extensively on a variety of other data to derive estimates of economic and fiscal impacts. For example, the model's estimation of economic impacts related to industry expenditures requires detailed data on the costs of individual OCS oil and gas activities, the distribution of expenditures across individual industries, the distribution of these expenditures across geographic areas, and the distribution of expenditures between labor expenditures and non-labor expenditures. Similarly, examples of the data used by the model to capture impacts related to industry profits include corporate income tax rates (federal and state), tax rates for dividend income, and the spatial distribution of government spending. Additional data used by the model are described throughout this report. The CIM is designed so that users can view and modify these data as appropriate.

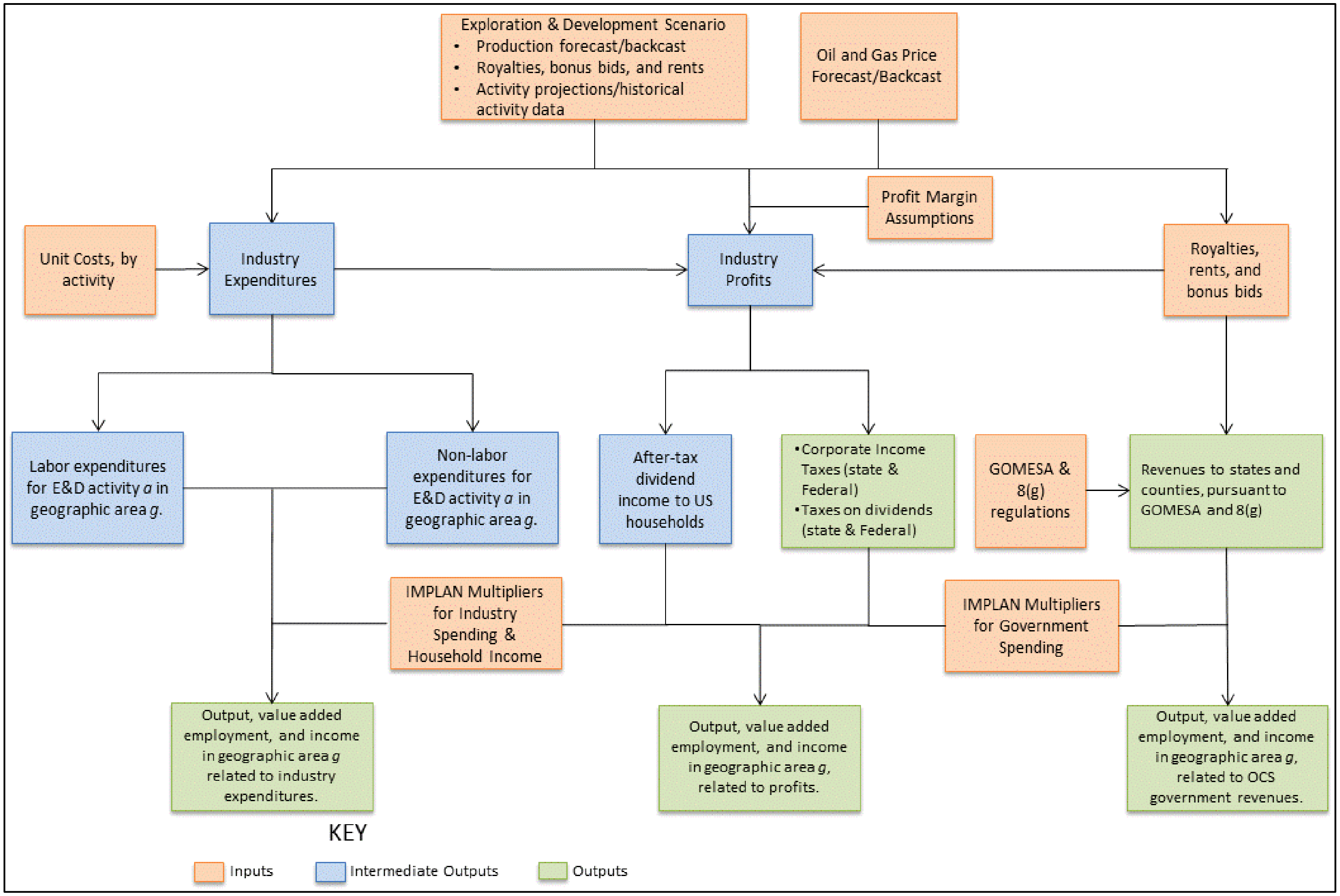

Figure 1. Structure of the Cumulative Impacts Model (CIM).

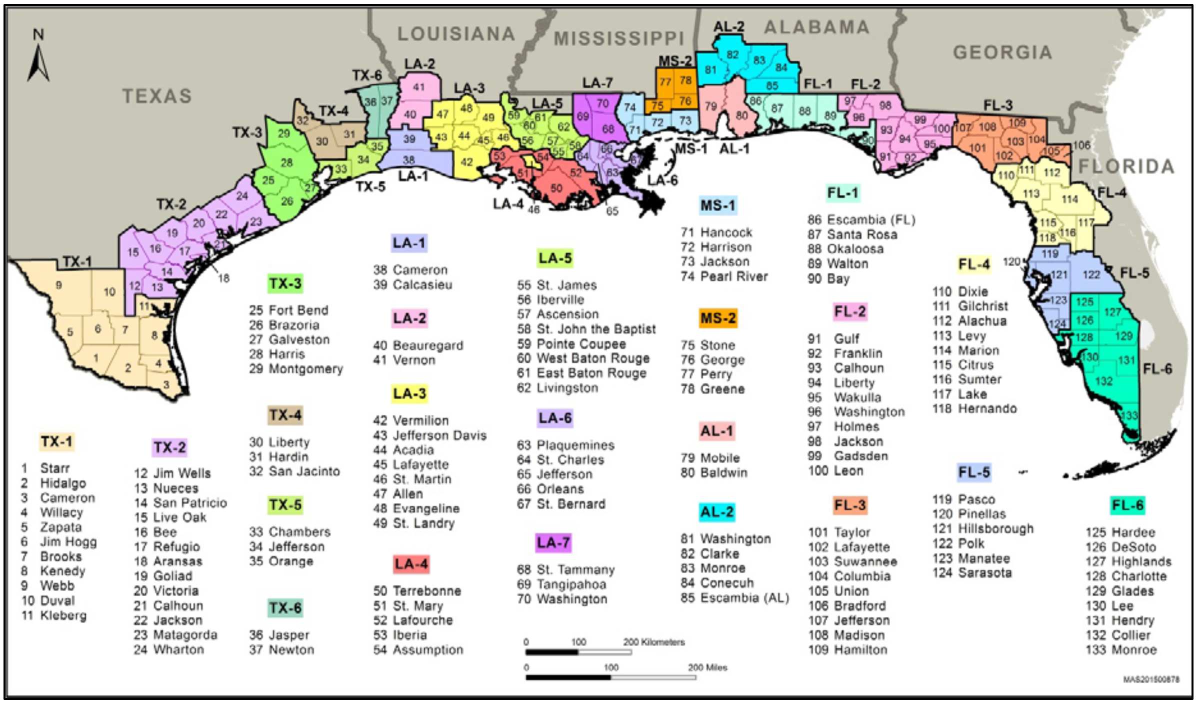

Figure 2. Gulf of Mexico economic impact areas (EIAs).

Source: Varnado and Fannin (2018)

For all types of impacts, the CIM also relies on data entered by the model user to specify the exploration and development scenario to be analyzed. This scenario, which is defined in detail in a cumulative exploration and development scenario spreadsheet, includes data on variables such as (but not limited to), the number of exploration wells drilled, the number of development wells drilled, platform construction, platform decommissioning, and OCS oil and gas production.

The CIM was designed to provide users with flexibility regarding the scope of their analyses and the assumptions applied in a given analysis. The model can be used to perform historical analyses of the economic and fiscal impacts associated with OCS oil and gas activity for a recent year or for forward-looking analyses that project these impacts over a 15-year period. For example, historical analyses for a recent year could support BOEM's contributions to the DOI's Economic Report series, which summarizes the economic impacts of recent DOI activities, while the model's forward-looking capabilities could support the development of BOEM's National OCS Oil and Gas Leasing Program. The exact years for which the CIM may conduct retrospective analyses depends on the years represented in the oil and gas price trajectory included in the model and the years represented in the historical OCS oil and gas activity data incorporated into the depreciation, depletion, and amortization (DD&A) calculations described in Chapter 5. Based on the default data included in the CIM at the time of this writing, the CIM may perform retrospective analyses as far back as 2005. The CIM also provides flexibility regarding several key data inputs, including the assumed effective corporate income tax rate on OCS oil and gas activity and the overall profitability of the OCS oil and gas industry. These and many other data inputs may be modified by the model user.

For ease of user access, the CIM was designed and programmed in Microsoft® Access®. The model includes an intuitive user interface where users can enter scenario-specific parameters, manage model data, perform model runs, and view results. The results include several standard reports with varying levels of detail on the economic and fiscal impacts associated with a scenario.

1.2 LCIM Overview

Figure 3 summarizes the overall structure of the LCIM. As the figure indicates, the LCIM first estimates the financial performance of the leases reflected in a user-defined leasing scenario. Such scenarios may reflect a single lease, bundle of leases associated with a lease sale, or National OCS Program. Based on the revenues and costs projected for the scenario, the model assesses the financial viability of the lease or leases under examination, measured in terms of NPV and payback period. As part of these calculations, the model generates estimates of (1) offshore oil and gas industry expenditures, (2) industry profits, and (3) OCS government revenues (i.e., royalties, bonus bids, and rents). For an individual lease or group of leases, the LCIM estimates the impacts associated with each of these items using the same approach as described above for the CIM. For example, like the CIM, the LCIM uses economic multipliers from IMPLAN to estimate the economic impacts associated with industry expenditures, government spending, and household spending. The LCIM's spatial resolution is also the same as described above for the CIM (i.e., for the 23 Gulf economic impact areas shown in Figure 2 and for individual states outside the Gulf region).

For all types of impacts, the LCIM relies on data entered by the model user to specify key details of the lease or leases to be analyzed. Such details include (but are not limited to) the amount of oil and gas to be produced on the lease, bonus bids, oil and gas prices, and the lease start year. Users may provide this and other related information in either (1) a detailed leasing scenario spreadsheet, in which data are entered for each year of the lease term, or (2) a streamlined leasing scenario input screen in the model itself that requires less data than the detailed leasing scenario spreadsheet. If the model user opts for the streamlined scenario input option, the LCIM applies a number of assumptions (detailed in Appendix A) in conjunction with the scenario data entered by the user to fully specify the scenario.

The LCIM was designed to provide users with flexibility regarding the scope of their analyses and the assumptions applied in a given analysis. The model can be used to estimate the lifecycle economic and fiscal impacts associated with the sale of an individual lease, a lease sale involving multiple leases, or all of the leases reflected in a National OCS Oil and Gas Leasing Program. The LCIM also provides flexibility regarding several key data inputs, including the assumed effective corporate income tax rate on OCS oil and gas activity, oil and gas prices, and the rent per acre on OCS leases. These and many other data inputs may be modified by the model user.

The LCIM was designed and programmed in Microsoft® Access® (like the CIM) and includes an intuitive user interface and several standard reports that contain varying levels of detail on the economic and fiscal impacts associated with a lease or group of leases.

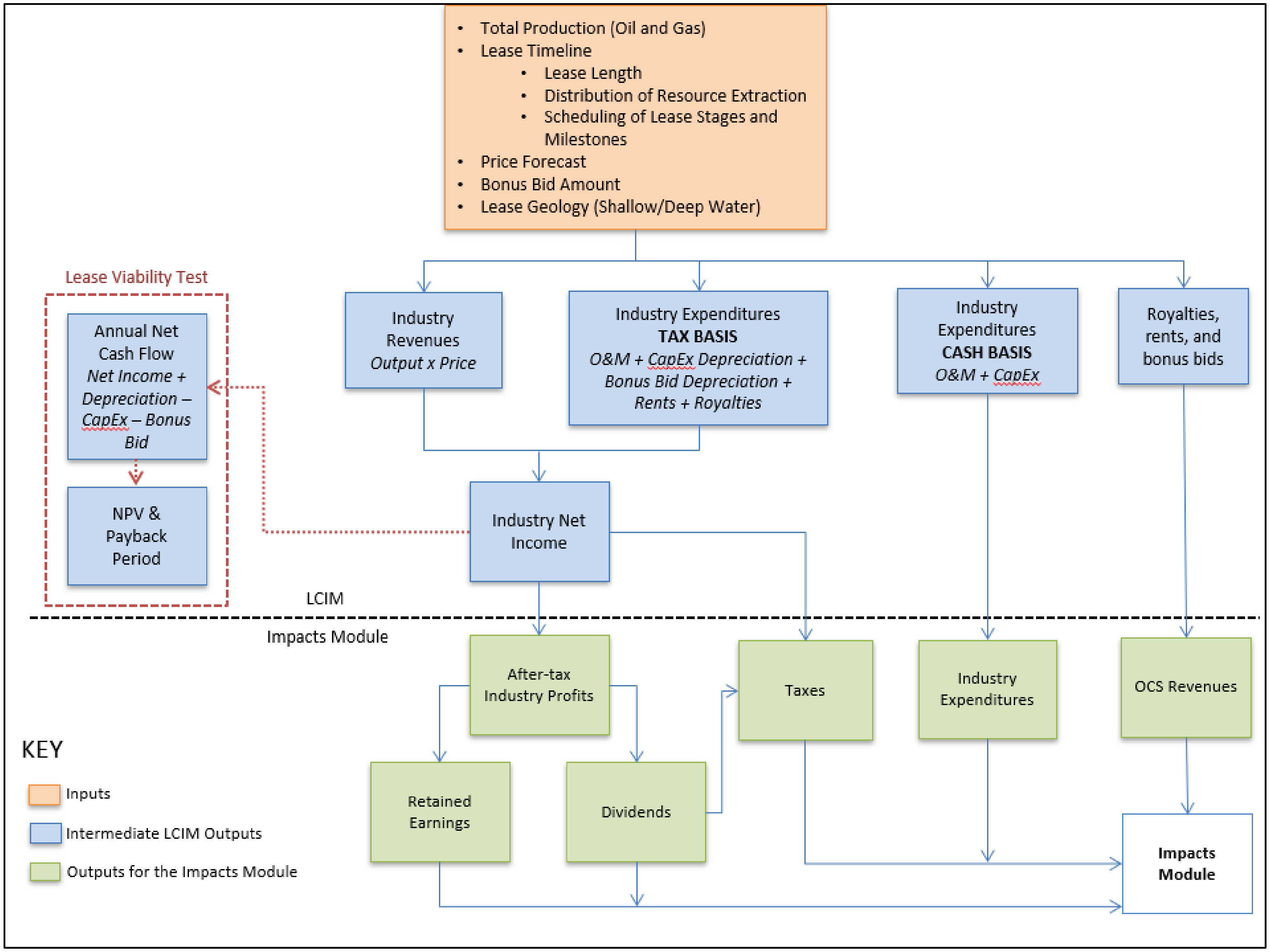

Figure 3. Structure of the Lifecycle Impacts Model (LCIM).

2 Scenario Input Data

2.1 Introduction

The analysis of economic and fiscal impacts in both the Cumulative Impacts Model (CIM) and (Lifecycle Impacts Model) LCIM is dependent on scenario-specific inputs provided by the user. Because the CIM and LCIM were designed for different (though related) purposes, the structure of the scenario data provided by users differs between the two models. These differences in input structure, coupled with differences in analytic purpose, account for many of the key analytic differences between the CIM and LCIM described in subsequent chapters. Thus, to provide context for subsequent chapters, this chapter outlines the structure and contents of the scenario data required by each model.

2.2 Key Differences Between CIM and LCIM Scenario Data

The CIM and LCIM serve slightly different analytic objectives. The CIM is designed to estimate the economic and fiscal impacts of all Outer Continental Shelf (OCS) oil and gas activity over the period of analysis, while the LCIM is designed to estimate economic and fiscal impacts over the full lifecycle of the subject lease or group of leases. These objectives highlight two key differences between the CIM and LCIM:

- ***Time period of analysis:*** The period of analysis in the CIM may include past years or future years, as the Bureau of Ocean Energy Management (BOEM) may use the model to assess impacts retrospectively for some analyses (e.g., to support the Department of the Interior's (DOI's) annual economic report) and prospectively for others (e.g., to analyze all future OCS oil and gas activity for planning purposes). With the option for retrospective or prospective analysis, the model accepts scenario data from one of two separate input templates for a given analysis: one template for retrospective analyses and a second for prospective analyses. In contrast, the LCIM's analysis of the economic and fiscal impacts associated with the sale of a lease or group of leases is an inherently forward-looking exercise, covering the period from the date of a lease sale to the lease's termination date.[3] Thus, LCIM users provide prospective scenario data only, in contrast to the CIM, which accepts retrospective *or* prospective scenario inputs for a given analysis.
- ***Scope of activity:*** The scope of activity covered by the CIM is much broader than that covered by the LCIM. Whereas the CIM is designed to assess impacts associated with *all* oil and gas activity on the Gulf of Mexico (Gulf) OCS, the LCIM's focus is limited to impacts associated with a specific lease or group of leases. Thus, the CIM requires data on all OCS activity whereas the LCIM requires information only for activity on some leases.

2.3 CIM Scenario Inputs

The CIM accommodates both prospective scenarios and retrospective scenarios specified by the model user. Users enter scenario data for both prospective and retrospective analyses into the CIM through exploration and development (E&D) scenario spreadsheets. One of the E&D spreadsheets is designed specifically for retrospective analyses estimating impacts for a single year of OCS oil and gas activity, while the other E&D spreadsheet is designed for prospective (forward-looking) analyses examining the impacts of OCS oil and gas activity over a 15-year time horizon. For *prospective* scenarios, users must provide the following data, by water depth category and year (unless otherwise noted below):

[3] Though the LCIM is forward-looking, it is possible to use the model to assess the impacts of past leases, from their date of issuance to their termination date.

- Exploratory & appraisal wells drilled (# of wells)
- Non-producing wells drilled (# of wells)
- "Production" wells–exploration wells re-entered and completed (# of wells)[4]
- "Production" wells–development wells drilled and completed (# of wells)
- Single well structures installed (# of structures)
- Single well structures in operation (# of structures)
- Single well structures removed (# of structures)
- Multi-well structures installed (# of structures)
- Multi-well structures in operation (# of structures)
- Multi-well structures removed (# of structures)
- "Structure" type–TLP, SPAR, SEMI installed (# of structures)
- "Structure" type–TLP, SPAR, SEMI in operation (# of structures)
- "Structure" type–TLP, SPAR, SEMI removed (# of structures)
- FPSO installed (water depth >1600m only) (# of FPSO)
- FPSO in operation (water depth >1600m only) (# of FPSO)
- FPSO removed (water depth >1600m only) (# of FPSO)
- "Structure" type–SUBSEA system installed (# of subsea)
- "Structure" type–SUBSEA system in operation (# of subsea)
- "Structure" type–SUBSEA system removed (# of subsea)
- Pipelines (miles installed)
- Oil Production Total (bbls; provided in aggregate by year, not by depth category)
- Gas Production Total (Mcf; provided in aggregate by year, not by depth category)
- Platforms Removed with Explosives (# of platforms)
- Platforms Removed without Explosives (# of platforms)
- Total bonus bid revenues ($ millions)
- Total rental revenues ($ millions)
- Total royalty revenues ($ millions)
- Total revenues ($ millions)
- 8(g) bonus bid revenues ($ millions)
- 8(g) rental revenues ($ millions)
- 8(g) royalty revenues ($ millions)

[4] The CIM assumes that this field only represents well completion activity for previously drilled exploratory wells. As a result, wells in this field receive only the unit cost associated with well completion (and not the cost associated with exploratory well drilling).

- 8(g) revenues total ($ millions)
- Non-8(g) bonus bid revenues ($ millions)
- Non-8(g) rental revenues ($ millions)
- Non-8(g) royalty revenues ($ millions)
- Non-8(g) revenues total ($ millions)
- Gulf of Mexico Energy Security Act (GOMESA bonus bid revenues ($ millions)
- GOMESA rental revenues ($ millions)
- GOMESA royalty revenues ($ millions)
- GOMESA revenues total ($ millions)
- Non-GOMESA bonus bid revenues ($ millions)
- Non-GOMESA rental revenues ($ millions)
- Non-GOMESA royalty revenues ($ millions)
- Non-GOMESA revenues total ($ millions)

For retrospective analyses, users provide much of the same information but for a single year only. In addition, because data are available on the *disbursement* of OCS revenues for previous years, users must provide data on such disbursements for retrospective analyses. Specifically, users must provide data on the following:

- Disbursements to states of OCS revenues subject to Section 8(g) of Outer Continental Shelf Lands Act (OCSLA).
- Land and Water Conservation Fund disbursements to states.
- Historic Preservation Fund disbursements to states.
- Disbursements to states of revenues subject to GOMESA revenue-sharing provisions.
- Disbursements of OCS revenues to the US Treasury General Fund.

2.4 LCIM Scenario Inputs

As described above, the LCIM prospectively estimates the economic and fiscal impacts associated with a given lease or group of leases. More specifically, the model estimates the economic and fiscal impacts of a single lease, a lease sale (involving multiple leases), or a National OCS Oil and Gas Leasing Program over time. For each scenario, users have two options for entering scenario data:

Detailed Leasing Scenario Spreadsheet: Under the first approach, the user populates a detailed leasing scenario spreadsheet that includes the exact frequency and timing of various OCS oil and gas activities (e.g., the number of exploratory wells drilled by year). After completing this spreadsheet, the user imports the scenario data into the model. Under this approach, timing and frequency information for individual OCS activities is provided directly by the user. The specific data to be entered by the user are the same as listed above for the CIM prospective E&D spreadsheet, with two exceptions. First, users must provide oil and gas production by water depth category rather than in total for a given year. Second, all data must be projected for the full life of the subject lease(s) rather than for just 15 years.

Streamlined Scenario Data Interface: Under the second approach, the user enters a smaller volume of information for the scenario via a streamlined leasing scenario interface within the LCIM itself. Using the more limited user-provided data in conjunction with various historical data that reside in the model for specific activities (see Appendix A), the LCIM generates a time series of OCS oil and gas activities for the leasing scenario. This approach puts less of a data entry burden on the user but assumes that the distribution of activity over time and the frequency of activity on a lease is consistent with historical data.

The streamlined interface requires a limited number of data inputs from the user, including, but not limited to, the following:

- Lease water depth
- Lease issuance year
- Number of leases (for multi-lease scenarios only)
- Total oil and gas production over the life of the lease (or group of leases).

To facilitate the LCIM's estimation of the trajectory of OCS oil and gas activities on a lease or group of leases, the streamlined leasing scenario interface also requires the user to select key assumptions regarding the level and timing of OCS activities on a lease. More specifically, users must choose which percentile to use from the statistical distributions stored in the model regarding (1) the level of OCS oil and gas activity and (2) the timing of such activity. The former includes the frequency of occurrence for OCS activities (e.g., the number of exploratory wells drilled), and the latter includes the number of years before a given OCS oil and gas activity begins following lease issuance and the number of years between the first and last occurrence of such activity (e.g., years between the first and last years when exploratory wells are drilled). As described in Appendix A, these distributions were developed based on the timing and frequency of OCS activities observed in historical activity datasets from the BOEM Data Center.

3 Impacts Related to Industry Expenditures

3.1 Introduction

The estimation of economic impacts associated with the offshore oil and gas industry's expenditures on a lease or group of leases represents a key component of the methods applied by the Cumulative Impacts Model (CIM) and Lifecycle Impacts Model (LCIM). Based on historical or projected industry activity entered by the user (in the case of the CIM) or lease scenario data entered by the user (in the case of the LCIM), the models each generate a time series of activity-specific industry expenditures. As shown in Figure 4, the models then allocate these expenditures to individual industries and geographic areas and apply a series of IMPLAN multipliers to estimate the economic impacts associated with these expenditures. The specific impacts estimated by the CIM and LCIM include the output, value added, income, and employment associated with a lease or group of leases. The models estimate these economic impacts for individual economic impact areas (EIAs) in the Gulf of Mexico (Gulf) states, the rest of state for each Gulf state, and for each individual state in the rest of the US.

The sections that follow in this chapter present the details of the approach applied in the CIM and LCIM for estimating the economic impacts associated with OCS industry expenditures. The chapter first presents the CIM and LCIM's approach for estimating industry expenditures for individual OCS oil and gas activities. Following this discussion, several sections are devoted to describing the models' approach for allocating an activity's expenditures between labor and non-labor, allocating non-labor expenditures to specific IMPLAN sectors, and distributing labor and non-labor expenditures to different geographic areas. After presenting these details on the allocation of industry expenditures, the chapter describes the specification of multipliers in the CIM and LCIM based on data from IMPLAN, what these multipliers represent, and how the CIM and LCIM apply them.

3.2 Industry Expenditures

The CIM and LCIM apply a bottom-up approach to estimating industry expenditures, based on available metrics of industry activity (e.g., number of exploration wells drilled) and data on the unit costs of each activity. Both models rely on estimates of industry activity, by year, to calculate industry expenditures, though the models differ in how they generate activity data:

- ***CIM specification of industry activity*** For prospective analyses, the CIM relies on estimates of industry activity, by year, included in the cumulative exploration and development (E&D) scenario entered by the user. For retrospective analyses, the CIM applies user-entered historical activity data.
- ***LCIM specification of industry activity*** The LCIM generates yearly activity data in one of two ways. First, these data may be obtained directly from a detailed leasing scenario spreadsheet imported by the user that includes data such as the number of exploratory and development wells drilled in a given year. Second, these may be derived from (1) more basic lease data entered by the user and (2) historical data residing in the LCIM characterizing the frequency and timing of individual OCS oil and gas activities (e.g., exploratory well drilling).[5]

[5] Both leasing scenario data entry options are described in detail in Chapter 2.

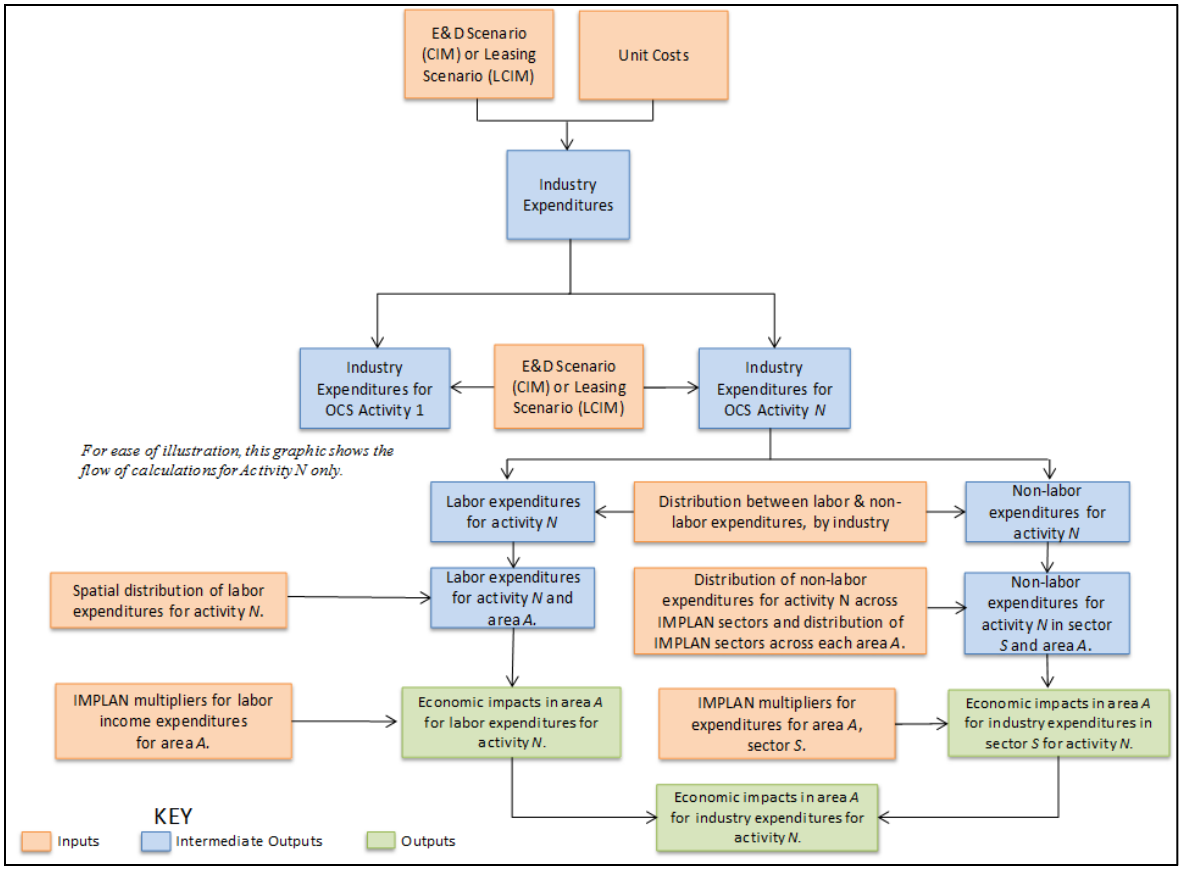

Figure 4. Schematic of CIM and LCIM approach for estimating economic impacts related to industry expenditures.

Note: The CIM and LCIM include separate calculations for labor expenditures and non-labor expenditures for only a subset of Outer Continental Shelf (OCS) oil and gas activities. This graphic shows both for the purposes of exposition.

To project the industry expenditures associated with these activities, both models apply the unit cost estimates and equations identified in Table 1.

The cost information presented in Table 1 reflects a combination of cost equations from the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS), unit cost data from the Bureau of Ocean Energy Management's (BOEM's) MAG-PLAN model (EIA 2017 and Kaplan et al. 2016), unit cost data from the BOEM Office of Resource Evaluation (RE),[6] and unit cost data from IHS Global's "Oil and Gas Upstream Cost Study" (IHS Global 2015). For exploratory and development drilling costs, the CIM and LCIM use the EIA-NEMS cost equations. The NEMS documentation provides separate cost equations for exploratory well drilling and development well drilling. For production wells, the models combine the NEMS drilling cost equations with well completion unit costs by water depth from the BOEM RE.[7] The use of the actual NEMS equations allows the CIM and LCIM to develop more refined cost estimates for each well (relative to the MAG-PLAN costs) based on water depth and oil prices; the oil price adjustments are applied to the values derived from the Cost Equation/Unit Cost column in Table 1.[8] Similarly, the models use the NEMS equations for the estimation of platform installation costs due to the greater flexibility provided by these equations to estimate costs as a function of water depth and the number of slots per platform. The NEMS documentation also includes equations for a greater number of platform types than MAG-PLAN. However, the NEMS documentation does not include separate equations for caissons or well protectors. For these categories, the CIM and LCIM rely on the BOEM Net Economic Value (NEV) model estimates for caisson costs by water depth category.[9] Additionally, the NEMS documentation does not include costs for all aspects of subsea well system installation.[10] As a result, the CIM and LCIM rely on IHS Global's (2015) "Oil and Gas Upstream Cost Study" to estimate subsea system installation costs.

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[6] BOEM provided Industrial Economics, Inc. with estimated unit costs for the GOM 2019 - 2024 Draft Proposed Program via email on March 7, 2019.

[7] The CIM and LCIM assign the following costs to each well drilling activity from the E&D Scenario:

- Exploratory & Appraisal Wells Drilled–NEMS exploratory well drilling equation
- Non-Producing Wells Drilled–NEMS development well drilling equation
- Production Wells–Exploration Wells Re-entered and Completed–20 percent of the NEMS development well drilling equation (based on the ratio identified by the BOEM Office of Resource Evaluation) plus the BOEM Office of Resource Evaluation well completion unit cost
- Production Wells–Development Wells Drilled and Completed–NEMS development well drilling equation plus the BOEM Office of Resource Evaluation well completion unit cost

[8] NEMS adjusts the base values produced by the cost equations based on the current oil price. The adjustment factor is $\left(0.6 + \ (oilprice/baseprice)\right)$, where *baseprice* is $75/barrel (2017$). The adjustment factor was obtained from EIA (2017).

[9] BOEM provided the NEV model costs to Industrial Economics, Inc. via email on March 23, 2018.

[10] The subsea cost from NEMS reflects only the cost of a subsea template for each development well producing to a floating platform. The NEMS documentation does not include costs for other components such as subsea manifolds, flowline and risers, subsea component connectors and jumpers, and the umbilical control system.

Table 1. Cost Equations/Unit Costs Applied in the CIM and LCIM

Activity Category	Water Depth–WD	Average Water Depth–AWD (ft)[1]	Average Drill Depth–DD (ft)[1]	Average Slots[1]	Cost Equation / Unit Cost	Oil Price Adjustment[2]	Source
Exploratory & Appraisal Wells Drilled	0–60m	79	11,935	NA	=2000000+(5*10^-9)*[WD]*[DD]^3	✓	NEMS
Exploratory & Appraisal Wells Drilled	60–200m	306	10,167	NA	=2000000+(5*10^-9)*[WD]*[DD]^3	✓	NEMS
Exploratory & Appraisal Wells Drilled	200–800m	1,675	13,005	NA	=2500000+400*[WD]+200*([WD]+[DD])+(2*10^-5)*[WD]*[DD]^2	✓	NEMS
Exploratory & Appraisal Wells Drilled	800–1600m	3,849	19,627	NA	=7500000+(1*10^-5)*[WD]*[DD]^2	✓	NEMS
Exploratory & Appraisal Wells Drilled	>1600m	6,775	21,507	NA	=7500000+(1*10^-5)*[WD]*[DD]^2	✓	NEMS
Non-Producing Wells Drilled	0–60m	92	11,173	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])	✓	NEMS
Non-Producing Wells Drilled	60–200m	290	9,566	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])	✓	NEMS
Non-Producing Wells Drilled	200–800m	1,390	13,762	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])	✓	NEMS
Non-Producing Wells Drilled	800–1600m	3,815	19,212	NA	=5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD])	✓	NEMS
Non-Producing Wells Drilled	>1600m	6,707	18,002	NA	=5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD])	✓	NEMS
Production Wells–Exploration Wells Re-entered and Completed	0–60m	NA	NA	NA	=0.2*(5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])) + 1849485	✓	NEMS, BOEM RE
Production Wells–Exploration Wells Re-entered and Completed	60–200m	NA	NA	NA	=0.2*(5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])) + 2986883	✓	NEMS, BOEM RE
Production Wells–Exploration Wells Re-entered and Completed	200–800m	NA	NA	NA	=0.2*(5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD])) + 8980056	✓	NEMS, BOEM RE
Production Wells–Exploration Wells Re-entered and Completed	800–1600m	NA	NA	NA	=0.2*(5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD])) + 21830876	✓	NEMS, BOEM RE
Production Wells–Exploration Wells Re-entered and Completed	>1600m	NA	NA	NA	=0.2*(5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD])) + 34480688	✓	NEMS, BOEM RE
Production Wells–Development Wells Drilled and Completed	0–60m	92	11,173	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD]) + 1849485	✓	NEMS, BOEM RE
Production Wells–Development Wells Drilled and Completed	60–200m	290	9,566	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD]) + 2986883	✓	NEMS, BOEM RE
Production Wells–Development Wells Drilled and Completed	200–800m	1,390	13,762	NA	=5*(1500000+(1500+0.04*[DD])*[WD]+(0.035*[DD]-300)*[DD]) + 8980056	✓	NEMS, BOEM RE

Activity Category	Water Depth–WD	Average Water Depth–AWD (ft)[1]	Average Drill Depth–DD (ft)[1]	Average Slots[1]	Cost Equation / Unit Cost	Oil Price Adjustment[2]	Source
Production Wells–Development Wells Drilled and Completed	800–1600m	3,815	19,212	NA	=5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD]) + 21830876	✓	NEMS, BOEM RE
Production Wells–Development Wells Drilled and Completed	>1600m	6,707	18,002	NA	=5*(4500000+(150+0.004*[DD])*[WD]+(0.035*[DD]-250)*[DD]) + 34480688	✓	NEMS, BOEM RE
Single Well Structures Installed	0–60m	NA	NA	NA	$1,499,677		NEV
Single Well Structures Operation	0–60m	NA	NA	NA	$1,116,559		MAG-PLAN
Single Well Structures Removed	0–60m	NA	NA	NA	$149,968		NEV/NEMS
Single Well Structures Installed	60–200m	NA	NA	NA	$6,599,724		NEV
Single Well Structures Operation	60–200m	NA	NA	NA	$1,116,559		MAG-PLAN
Single Well Structures Removed	60–200m	NA	NA	NA	$659,972		NEMS
Multi Well Structures Installed	0–60m	92	NA	3	=2000000+9000*[SLOTS]+1500*[WD]*[SLOTS]+40*[WD]^2	✓	NEMS
Multi Well Structures Operation	0–60m		NA		$1,116,559		MAG-PLAN
Multi Well Structures Removed	0–60m	92	NA	3	=0.1*(2000000+9000*[SLOTS]+1500*[WD]*[SLOTS]+40*[WD]^2)	✓	NEMS
Multi Well Structures Installed	60–200m	280	NA	5	=2000000+9000*[SLOTS]+1500*[WD]*[SLOTS]+40*[WD]^2	✓	NEMS
Multi Well Structures Operation	60–200m		NA		$1,116,559		MAG-PLAN
Multi Well Structures Removed	60–200m	280	NA	5	=0.1*(2000000+9000*[SLOTS]+1500*[WD]*[SLOTS]+40*[WD]^2)	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Installed	200–800m	1,943	NA	5	=(3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%]	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Installed	800–1600m	3,907	NA	11	=(3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%]	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Installed	>1600m	6,424	NA	8	=(3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%]	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Operation	200–800m	NA	NA	NA	$4,895,129		MAG-PLAN
“Structure” Type–TLP, SPAR, SEMI Operation	800–1600m	NA	NA	NA	$12,152,250		MAG-PLAN
“Structure” Type–TLP, SPAR, SEMI Operation	>1600m	NA	NA	NA	$12,152,250		MAG-PLAN

Activity Category	Water Depth–WD	Average Water Depth–AWD (ft)[1]	Average Drill Depth–DD (ft)[1]	Average Slots[1]	Cost Equation / Unit Cost	Oil Price Adjustment[2]	Source
“Structure” Type–TLP, SPAR, SEMI Removed	200–800m	1,943	NA	5	=0.1*((3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%])	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Removed	800–1600m	3,907	NA	11	=0.1*((3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%])	✓	NEMS
“Structure” Type–TLP, SPAR, SEMI Removed	>1600m	6,424	NA	8	=0.1*((3.5*([SLOTS]+20)*(3000000+500*([WD]-1000)))*[SPAR%]+(2*([SLOTS]+30)*(3000000+750*([WD]-1000)))*[TLP%])	✓	NEMS
FPSO Installed	>1600m	8,930	NA	8	=([SLOTS]+20)*(7500000+250*([WD]-1000))	✓	NEMS
FPSO Operation	>1600m		NA	NA	$12,152,250		MAG-PLAN
FPSO Removed	>1600m	8,930	NA	8	=0.1*(([SLOTS]+20)*(7500000+250*([WD]-1000)))	✓	NEMS
“Structure” Type–SUBSEA System Installed	200–800m	NA	NA	NA	$250,000,000	✓	IHS
“Structure” Type–SUBSEA System Installed	800–1600m	NA	NA	NA	$250,000,000	✓	IHS
“Structure” Type–SUBSEA System Installed	>1600m	NA	NA	NA	$250,000,000	✓	IHS
“Structure” Type–SUBSEA System Operation	200–800m	NA	NA	NA	$4,895,129		MAG-PLAN
“Structure” Type–SUBSEA System Operation	800–1600m	NA	NA	NA	$4,895,129		MAG-PLAN
“Structure” Type–SUBSEA System Operation	>1600m	NA	NA	NA	$4,895,129		MAG-PLAN
“Structure” Type_SUBSEA System Removed	200–800m	NA	NA	NA	$25,000,000	✓	NEMS
“Structure” Type–SUBSEA System Removed	800–1600m	NA	NA	NA	$25,000,000	✓	NEMS
“Structure” Type–SUBSEA System Removed	>1600m	NA	NA	NA	$25,000,000	✓	NEMS
Pipeline	All	NA	NA	NA	$2,384,674		MAG-PLAN

Notes: 1. The average water depth, drill depth, and number of slots was calculated based on historical well drilling and structure installation activity from year 2000 to the present.

2. The oil price adjustment factor is calculated as 0.6+([Oil_Price]/75).

3. All costs are adjusted to 2017 dollars using the Implicit Price Deflator for Gross Domestic Product from the Bureau of Economic Analysis.

For offshore pipeline construction, offshore pipeline operation and maintenance (O&M), and production O&M, the CIM and LCIM apply the MAG-PLAN unit cost data. For the pipeline cost components, MAG-PLAN is used due to the lack of relevant cost equations in the NEMS documentation. Though the NEMS documentation does include an equation to estimate production O&M, a comparison of the historical O&M costs implied by the unit cost data from NEMS, MAG-PLAN, BOEM's NEV model, and Wood McKenzie data obtained by BOEM suggest that the MAG-PLAN data are the best fit. As shown in Figure 5, when these O&M costs are compared to data for major energy producers from EIA's Financial Reporting System (FRS), the O&M costs for MAG-PLAN clearly track the FRS data more closely than the NEMS data and the Wood McKenzie data.[11] Though the O&M costs from MAG-PLAN follow a similar track as those from BOEM's NEV model through 2003, the MAG-PLAN data are a better fit from 2004 onward. The CIM and LCIM assign production O&M costs to all structures in operation in each year specified in the E&D Scenario.

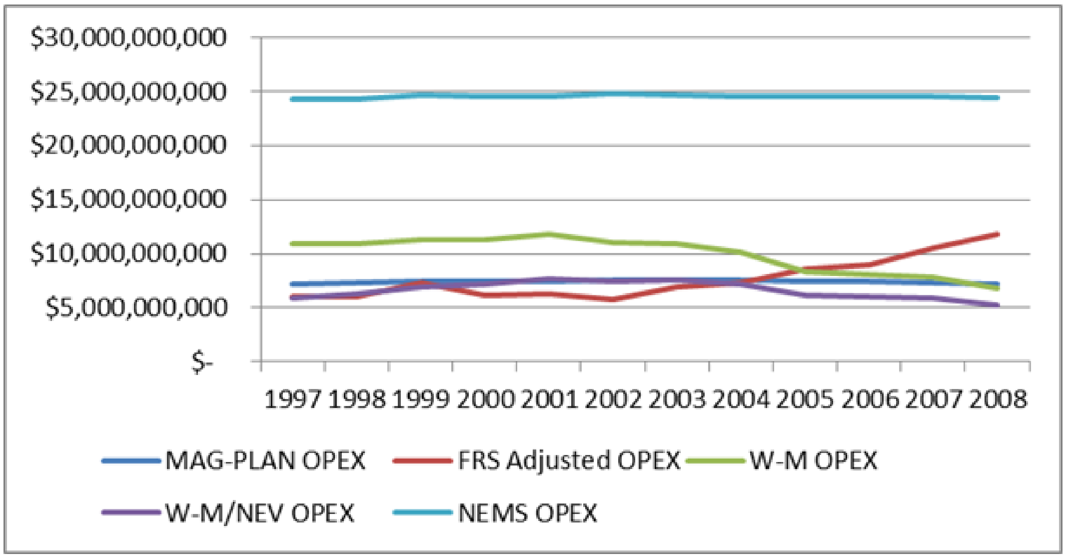

Figure 5. Comparison of historical O&M costs based on alternative unit cost assumptions.

MAG-PLAN OPEX: Unit costs values from MAG-PLAN (Kaplan et al. 2016).

W-M OPEX: Wood-Mackenzie values, applied to all O&M[12].

W-M/NEV OPEX: Wood-Mackenzie values used for production in deep and ultra-deep water. NEV values used for other water depths.[13]

FRS Adjusted OPEX: EIA FRS values for major energy producers scaled in proportion to offshore production reflected in FRS data (EIA 1999–EIA 2011).

NEMS OPEX: Unit cost values used in NEMS, as reported in EIA (2017). Note that these values do not reflect price adjustments. Price-adjusted O&M costs would be even higher than shown here.

[11] The EIA FRS data reflect operating costs for major energy producers. From 1997 to 2009, these producers accounted for 55 to 67 percent of total OCS oil production. In each year, total OCS operating costs were estimated by dividing the operating costs for the major energy producers by the percentage of total OCS oil production attributed to these producers.

[12] BOEM provided Industrial Economics, Inc. with cost information from Wood-Mackenzie on 21 pre-FID fields in the Gulf of Mexico via email on March 23, 2018.

[13] BOEM provided the NEV model costs to Industrial Economics, Inc. via email on March 23, 2018.

The CIM and LCIM estimate costs for geological and geophysical (G&G) surveys as a percentage of exploratory well drilling activity. This percentage was estimated based on historical data on G&G expenditures and exploratory drilling expenditures from EIA's Performance Profiles of Major Energy Producers (EIA 1997–EIA 2009). From 1997 to 2009, expenditures on G&G were on average 26 percent of expenditures on exploratory drilling and equipping. The CIM and LCIM apply this 26 percent estimate to their estimates of exploratory well drilling costs derived from the NEMS cost equations to estimate total G&G costs in each year.

Other key assumptions in the models' estimation of expenditures based on the cost functions outlined above include the following:

- For the well drilling and platform installation cost equations, the CIM and LCIM rely on average water depths, drill depths, and slot counts based on historical BOEM data from year 2000 to the present.
- To estimate costs for the E&D scenario activity '"Structure" Type–TLP, SPAR, SEMI Installed', the proportion of installations of each structure type based on historical BOEM data from year 2000 to the present was estimated. The CIM and LCIM use this distribution to estimate installations of SPARs and TLPs separately. The models then apply the NEMS SPAR equation to the estimated SPAR portion of installations and the NEMS TLP equation to the estimated TLP portion. NEMS did not provide a separate cost equation for SEMI platforms, so it groups them with TLPs.
- NEMS provides separate cost equations for three different types of exploratory drilling rigs: (1) jack-up rigs, (2) semi-submersible rigs, and (3) dynamically positioned drill ships. The NEMS documentation notes that "water depth is the primary criterion for selecting a drilling rig." Based on the descriptions provided in the NEMS documentation, the CIM and LCIM apply the jack-up rig cost to exploratory wells in the 0–60m and 60–200m water depths, the semi-submersible rig cost to exploratory wells in the 200–800m water depth, and the dynamically positioned drill ship cost to the exploratory wells in the 800–1600m and >1600m water depths.
- The CIM and LCIM rely on a subsea system installation cost estimate from IHS Global (EIA 2016). The cost estimate reflects two satellite wells at a water depth of 5,000 feet tied back to a floating production platform at a distance of 15 miles. The models rely on the NEMS documentation for subsea system removal costs (estimated at 10 percent of installation costs).

3.3 Distribution of Expenditures Across OCS Activities

Under the approach described above for the estimation of industry expenditures, the CIM and LCIM generate expenditure estimates unique to individual OCS oil and gas activities, such as development well drilling, platform construction, platform operations, etc. As described above, the distribution of expenditures across activities within each model reflects the activity estimates that are either obtained from a detailed scenario spreadsheet imported by the user or (in the case of the LCIM) derived from the more streamlined scenario data provided via the user interface.

The activity estimates imported into or calculated by the models include estimates of the number of structures installed by water depth in each year. In both cases, the scenario data specify installations separately for the following types of structures:

- Single well structures
- Multi well structures
- TLP, SPAR, SEMI
- FPSO
- SUBSEA system

The CIM and LCIM allocate the projected number of installations for each of these structure types in each year to the matching structure types identified in the NEMS equations. However, NEMS contains multiple equations relevant to the “TLP, SPAR, SEMI” structure category. As a result, the CIM and LCIM allocate the projected number of “TLP, SPAR, SEMI” installations to the specific platform types identified in the NEMS equations based on the historical distribution of platform types by water depth.

3.4 Distribution Between Labor and Non-Labor Expenditures

For the purposes of estimating the economic impacts associated with industry expenditures, the CIM and LCIM distinguish between labor and non-labor expenditures for select OCS activities. As indicated in the results of BOEM’s 2008 Labor Needs Survey (ICF Consulting 2008), platform production workers spend multiple days at the production site followed by multiple days off, which allows for extended commuting distances for production workers. Thus, production workers may not necessarily live in close proximity to production sites. Similarly, based on an industry survey conducted by the International Association of Drilling Contractors (IADC) following the 2010 *Deepwater Horizon* oil spill, the employees of offshore drilling contractors reside in approximately two-thirds of US Congressional Districts (IADC 2010).

Based on these findings, the spatial distribution of the economic impacts associated with industry production and drilling expenditures on labor is likely to differ from the distribution of impacts associated with non-labor expenditures for these activities. Therefore, to accurately capture the spatial distribution of economic impacts, it is important for the CIM and LCIM to distinguish between labor expenditures and non-labor expenditures for production and drilling activities. To distribute industry expenditures between labor and non-labor for these activities, the models use the distributions applied in BOEM’s MAG-PLAN model, as presented in Table 2. For the OCS activities not shown in the table, the CIM and LCIM do not distinguish between labor and non-labor expenditures.

Table 2. Distribution between Labor and Non-labor Expenditures for Select OCS Activities

Activity	Water Depth	Labor Percentage	Non-Labor Percentage
Exploratory well drilling	All	19.9	80.1
Nonproductive well drilling	All	24.2	75.8
Development well drilling	All	23.8	76.2
Production O&M	0–60 meters	32.5	67.5
	60–200 meters	27.9	72.1
	200+ meters	25.0	75.0

Source: Kaplan et a. 2016

3.5 Distribution of Non-Labor Expenditures Across IMPLAN Sectors

After the CIM and LCIM estimate expenditures for a given year for all OCS activities, the models distribute the non-labor expenditures for each activity across all relevant IMPLAN sectors. The models base this allocation on the corresponding allocation in MAG-PLAN. As described in the MAG-PLAN documentation, MAG-PLAN distributes non-labor expenditures across 166 of the 440 sectors included in IMPLAN 2012 (Kaplan et al. 2016). As indicated in Chapter 1 and described in more detail in Section 3.8 below, however, the CIM and LCIM use multipliers from IMPLAN 2017, which includes 536 sectors. Therefore, though MAG-PLAN’s distribution of non-labor expenditures across IMPLAN sectors may provide a starting point for allocating expenditures within the LCIM, a bridge must be applied between the outdated IMPLAN 440 sectors and the current IMPLAN 536 sectors.

For most sectors, the CIM and LCIM adapt the allocation from MAG-PLAN based on the bridge that IMPLAN developed to convert IMPLAN 440 to IMPLAN 536 sectors (IMPLAN 2015). For a given

IMPLAN 440 sector, the bridge identifies the corresponding IMPLAN 536 sector(s) and the proportional distribution of activity across those sectors. In some cases, the CIM and LCIM deviate from the bridge developed by IMPLAN, to avoid allocating expenditures to an industry that does not exist in some areas or to represent offshore oil and gas activities more accurately. For example, though the IMPLAN bridge allocates sector 31 (electric power generation, transmission, and distribution) from IMPLAN 440 to fossil fuel electric power generation, electric power transmission and distribution, hydroelectric, nuclear, solar, wind, geothermal, biomass, and tidal generation in IMPLAN 2017, the CIM and LCIM exclude hydroelectric, nuclear, solar, wind, geothermal, biomass, and tidal generation from the crosswalk. Though these are valid forms of electricity generation, they may not be present in all of the geographic areas represented in the LCIM (e.g., an economic impact area may not have nuclear generation). In addition, because renewable generation is driven by policy as much as by market conditions, it is unclear to what extent marginal changes in electricity demand would affect demand for solar, wind, geothermal, biomass, or tidal generation.

Table 3 below identifies the CIM's and LCIM's deviations from the IMPLAN 440-536 crosswalk. For the cases in which the models exclude specific IMPLAN 536 sector(s) mapped to a given IMPLAN 440 sector, the models proportionately reallocate to the remaining IMPLAN 536 sectors mapped to that IMPLAN 440 sector. The one exception to this is IMPLAN 440 Sector 31. The CIM and LCIM assume that Sector 49 (Electric power transmission and distribution) retains the 55 percent allocation from the IMPLAN bridge, while Sector 42 (Fossil fuel electric power generation) accounts for all electricity generation, or 45 percent of the allocation. This approach retains the relative balance between electricity transmission/distribution and generation.

Note that the approach described above applies to non-labor expenditures only. Consistent with the approach in MAG-PLAN, the CIM and LCIM do not allocate labor expenditures to individual industries but instead treat them as an increase in household income.

Table 3. Modifications to IMPLAN's Bridge between IMPLAN 440 and IMPLAN 536 Sectors

IMPLAN 440 Sector	Description	Ratio	IMPLAN 536 Sector	Description	IMPLAN 536 sector(s) excluded
24	Mining gold, silver, and other metal ore	34%	29	Other metal ores	(28) Uranium-radium-vanadium ores
		64%	24	Gold ores	
		2%	25	Silver ores	
31	Electric power generation, transmission, and distribution	45%	42	Fossil fuel electric power generation	Other power generation: (41) Hydroelectric, (43) Nuclear, (44) Solar, (45) Wind, (46) Geothermal, (47) Biomass, (48) Tidal.
		55%	49	Electric power transmission and distribution	
36	Construction of other new nonresidential structures	100%	58	Other nonresidential structures	(54) Power and communication structures, (56) Highways and streets
39	Maintenance and repair construction of nonresidential structures	100%	62	Nonresidential maintenance and repair	(64) Maintenance and repair of highways, streets, bridges, and tunnels
141	All other chemical product and preparation manufacturing	6%	184	Explosives manufacturing	(186) Photographic film and chemical manufacturing
		24%	185	Custom compounding of purchased resins	
		70%	187	Other miscellaneous chemical product manufacturing	
130	Fertilizer manufacturing	51%	169	Nitrogenous fertilizer manufacturing	(171) Fertilizer, mixing only, manufacturing
		49%	170	Phosphatic fertilizer manufacturing	
207	Other industrial machinery manufacturing	100%	271	All other industrial machinery manufacturing	(267) Food product machinery manufacturing, (269) Sawmill, woodworking, and paper machinery, (270) Printing machinery and equipment manufacturing
228	Material handling equipment manufacturing	100%	292	Overhead cranes, hoists, and monorail systems	(290) Elevator and moving stairway manufacturing, (291) Conveyor and conveying equipment manufacturing, (293) Industrial truck, trailer, and stacker manufacturing

3.6 Spatial Allocation of Labor Expenditures

After the CIM and LCIM have determined the portion of total expenditures that are labor expenditures, the models allocate these expenditures to onshore areas using a similar allocation scheme as in MAG-PLAN. MAG-PLAN allocates labor expenditures separately for drilling activities and production O&M activities. The spatial allocation for drilling activities, shown in Table 4, is based on survey data from the International Association of Drilling Contractors (IADC) (2010) while the allocation for production O&M activities, shown in Table 5, reflects survey data from BOEM's 2008 Labor Needs Survey (ICF Consulting 2008). Though MAG-PLAN further disaggregates the allocation to the county level, the CIM and LCIM use BOEM EIAs as the finest level of spatial disaggregation for labor expenditures. Outside the Gulf coastal zone, the CIM and LCIM allocate labor expenditures to each rest-of-state area for the states in the Gulf region (i.e., Texas, Louisiana, Mississippi, Alabama, and Florida) and to the rest of the US.

Table 4. Spatial Allocation of Labor Expenditures for Drilling Activities

Onshore Area	Share of Total	Onshore Area	Share of Total
TX-1	1.04%	MS-1	3.10%
TX-2	0.85%	MS-2	0.49%
TX-3	20.87%	Rest of Mississippi	17.03%
TX-4	0.77%	AL-1	1.28%
TX-5	1.08%	AL-2	0.32%
TX-6	0.33%	Rest of Alabama	6.40%
Rest of Texas	11.15%	FL-1	1.42%
LA-1	1.62%	FL-2	0.19%
LA-2	0.72%	FL-3	0.05%
LA-3	4.64%	FL-4	0.14%
LA-4	3.09%	FL-5	0.23%
LA-5	2.61%	FL-6	0.07%
LA-6	1.88%	Rest of Florida	0.67%
LA-7	0.86%	Rest of U.S.	7.29%
Rest of Louisiana	9.78%	TOTAL	100%

Source: IADC (2015), as presented in Kaplan et al. (2016).

Table 5. Spatial Allocation of Labor Expenditures for Production Operations and Maintenance (O&M)

Onshore Area	Share of Total	Onshore Area	Share of Total
TX-1	1.51%	AL-1	2.77%
TX-2	1.19%	AL-2	0.56%
TX-3	23.17%	Rest of Alabama	0.00%
TX-4	0.83%	FL-1	1.05%
TX-5	0.17%	FL-2	0.61%
TX-6	0.01%	FL-3	0.28%
Rest of Texas	6.54%	FL-4	0.00%
LA-1	1.06%	FL-5	0.00%
LA-2	0.34%	FL-6	0.00%
LA-3	15.83%	Rest of Florida	0.00%
LA-4	14.84%	Ark. and Tenn.	0.82%
LA-5	3.88%	West Coast	0.79%
LA-6	10.78%	Other Lower 48	0.94%
LA-7	3.93%	Total	100%
Rest of Louisiana	3.82%		
MS-1	3.71%		
MS-2	0.57%		
Rest of Mississippi	0.00%		

Source: Kaplan et al. (2016).

As shown in Tables 4 and 5 above, the spatial distributions obtained from MAG-PLAN for labor expenditures include limited detail for areas outside the Gulf region. For well drilling, the data in Table 4 combine all states outside the Gulf region into a single "rest of U.S." area, while the data for production operations and maintenance (O&M) in Table 5 split states outside the Gulf into three groups (i.e., Arkansas and Tennessee combined, the West Coast, and all other Lower 48 states). Because the CIM and LCIM apply state-level IMPLAN multipliers for expenditures outside the Gulf region (see Section 3.8 below), these labor expenditure allocations must be further distributed to individual states.

To allocate the non-Gulf labor expenditures to individual states, the CIM and LCIM use the standard economic gravity equation:

$$(1)\quad L_{as} = \frac{F_s D_{lag}}{d_{sg}}$$

Where:

L_{as} = Labor expenditures for Gulf of Mexico OCS oil and gas activity *a* in state *s*;

F_s = Labor force in state *s*;

D_{lag} = Demand for labor for Gulf of Mexico OCS oil and gas activity *a*;

d_{sg} = Distance between state *s* and the production centroid of the Gulf, defined according to the barrel of oil equivalents (BOEs) produced on individual leases between 2013 and 2017 (see Figure 6).

Because the standard gravity approach represented in Equation 1 does not constrain the values of L_{as} such that total labor supply summed across individual states equals the amount demanded for well drilling and production O&M in the Gulf region, the CIM and LCIM normalize L_{as} to derive an estimate of the percentage of labor expenditures associated with an individual state:

$$F_{as} = \frac{L_{as}}{\sum_s L_{as}} \quad (2)$$

where F_{as} is the fraction of labor expenditures for Gulf OCS activity a allocated to state s. The estimated value for F_{as} is applied to the labor expenditures associated with well drilling and production O&M.

The CIM and LCIM differ somewhat in the application of Equations 1 and 2 for the distribution of labor expenditures for drilling activities and labor expenditures for O&M. As indicated in Table 4, the IADC data for non-Gulf labor expenditures for drilling activities include a single "Rest of U.S." percentage. The CIM and LCIM therefore apply Equations 1 and 2 to allocate this single value to individual states. In contrast, the data for O&M labor expenditures include three distinct areas outside the Gulf region: (1) Arkansas and Tennessee, (2) the West Coast, and (3) Other Lower 48. The CIM and LCIM apply Equations 1 and 2 separately for each of these three groups of states.

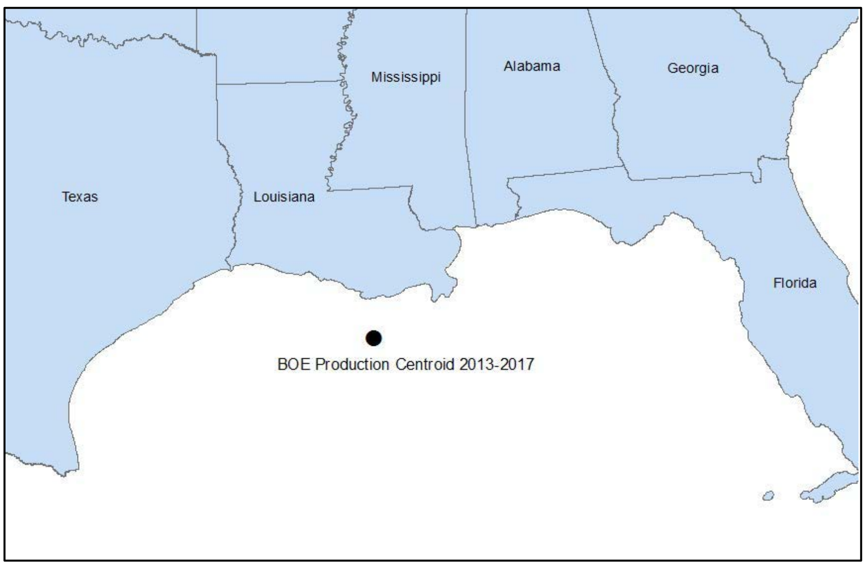

Figure 6. Gulf of Mexico oil and gas production centroid.

3.7 Spatial Allocation of Non-Labor Expenditures

After the CIM and LCIM have determined the portion of total expenditures that are non-labor expenditures, the models allocate these expenditures to different geographic areas. In performing this allocation, the CIM and LCIM rely on the following classification scheme used in MAG-PLAN to organize this allocation process:

> ***Major, local industries:*** These sectors are closely connected with offshore oil and gas operations, and support from these industries is assumed to be provided by firms in the Gulf region (i.e., all of the EIAs in Figure 2 combined). The industries in this category include IMPLAN 536 Sectors 408 (Air transportation) and 410 (Water transportation).
>
> ***Major, non-local industries:*** These sectors are also closely connected with offshore oil and gas operations, but support from these industries is assumed to be provided by firms both within and outside the Gulf region. The industries that make up this category include the following IMPLAN 536 Sectors:
>
> - Drilling oil and gas wells (IMPLAN sector 37)
> - Support activities for oil and gas operations (IMPLAN sector 38)
> - Iron and steel mills and ferroalloy manufacturing (IMPLAN sector 217)
> - Iron, steel pipe and tube manufacturing from purchased steel (IMPLAN sector 218)
> - Rolled steel shape manufacturing (IMPLAN sector 219)
> - Steel wire drawing (IMPLAN sector 220)
> - Mining machinery and equipment manufacturing (IMPLAN sector 265)
> - Oil and gas field machinery and equipment manufacturing (IMPLAN sector 266)
> - Wiring device manufacturing (IMPLAN sector 340)
> - Ship building and repairing (IMPLAN sector 363)
> - Insurance carriers (IMPLAN sector 437)
> - Architectural, engineering, and related services (IMPLAN sector 449)
>
> ***Non-major, local industries:*** These industries are not closely connected with offshore oil and gas development, but support from these industries is assumed to be provided by firms in the Gulf region. This category includes the remaining IMPLAN 536 Sectors 396 to 536.
>
> ***Non-major, non-local industries:*** These industries are also not closely connected with offshore oil and gas development. Support from these industries, which include the remaining IMPLAN 536 Sectors 1 to 395, is assumed to be provided by firms both within and outside the Gulf region.

The sections that follow describe the approach used in the CIM and LCIM for allocating expenditures for each of these categories. This approach applies to both non-labor expenditures and expenditures for activities for which the CIM and LCIM make no distinction between labor expenditures and non-labor expenditures.

3.7.1 Major, Local Industries

The major, local industries in the CIM and LCIM include the following:

- Water transportation (IMPLAN sector 410) and
- Air transportation (IMPLAN sector 408)

The models rely on data unique to each of these sectors to allocate their expenditures.

Water transportation: The spatial distribution for water transportation reflects the locations of 144 facilities identified as providing water transportation services to offshore operations in the Gulf . Kaplan et al. (2011) presents the year 2007 revenues for these facilities at the county level. The CIM and LCIM sum these county-level data by EIA to develop a distribution across EIAs (see Table 6) and allocates water transportation expenditures based on this distribution.

Table 6. Spatial Distributions for Water Transportation, Air Transportation, and Food Service

EIA	Air Transportation	Water Transportation	Full-Service Restaurants	Limited-Service Restaurants
AL1	0.06%	0.62%	3.69%	3.25%
AL2	0.00%	0.00%	0.13%	0.40%
FL1	0.00%	0.00%	5.94%	4.38%
FL2	0.00%	0.00%	1.41%	1.78%
FL3	0.00%	0.00%	0.26%	0.43%
FL4	0.00%	0.00%	3.14%	2.70%
FL5	0.00%	0.13%	11.29%	9.37%
FL6	0.00%	0.00%	5.06%	2.83%
LA1	49.74%	25.55%	0.87%	1.66%
LA2	0.00%	0.00%	0.20%	0.30%
LA3	8.44%	2.68%	3.04%	4.15%
LA4	26.10%	43.76%	2.74%	4.25%
LA5	2.35%	3.37%	6.06%	7.49%
LA6	0.00%	6.04%	14.01%	11.13%
LA7	0.00%	0.00%	2.92%	3.24%
MS1	0.00%	0.00%	2.26%	2.83%
MS2	0.00%	0.00%	0.07%	0.22%
TX1	0.00%	0.18%	2.75%	3.77%
TX2	0.06%	0.04%	2.16%	3.39%
TX3	13.25%	15.62%	30.11%	29.30%
TX4	0.00%	0.00%	0.25%	0.60%
TX5	0.00%	2.01%	1.59%	2.36%
TX6	0.00%	0.00%	0.07%	0.16%

Air transportation: The CIM's and LCIM's spatial distribution for air transportation reflects data available on 64 locations identified by Kaplan et al. (2011) as providing helicopter transportation services in the Gulf region. Using county level year 2007 revenues for these facilities, as reported in Kaplan et al. (2011), the CIM and LCIM develop a distribution of these revenues across EIAs. This distribution, shown in Table 6, serves as the basis for the models' allocation of air transportation expenditures to individual EIAs.

3.7.2 Major, Non-Local Industries

For major, non-local industries, the CIM and LCIM allocate expenditures based on Gulf Coast Oil Directory data as summarized in BOEM's analysis of the Gulf's oil services contract industry (Kaplan et al. 2011). These distributions are consistent with those in BOEM's MAG-PLAN model, as documented in Kaplan et al. (2016) and Kaplan et al. (2012).

3.7.3 Non-Major, Local Industries

For non-major, local sectors, all demand is assumed to be supplied locally in the combined EIA region. Specifically, the CIM's and LCIM's allocation of expenditures for non-major, local industries reflects the standard economic gravity equation:

$$(3)\quad X_{i,jg} = \frac{Y_{i,j}E_{i,g}}{d_{jg}}$$

Where:

$X_{i,jg}$ = Sales from industry *i* in EIA *j* to serve production in the Gulf.

$Y_{i,j}$ = Output produced by industry *i* in EIA *j*, as obtained from IMPLAN;

$E_{i,G}$ = Gulf demand for goods produced by industry *i*;

d_{jg} = Distance between EIA *j* and the production centroid of the Gulf of Mexico, defined according to the BOE equivalents produced on individual leases between 2013 and 2017 (see Figure 6).

Because the standard gravity equation does not constrain the values of $X_{i,jg}$ such that the amount supplied to the Gulf by EIAs is equal to demand, the CIM and LCIM estimate the amount supplied by individual EIAs in proportion to the value of $X_{i,jg}$ estimated for each EIA (i.e., using a normalization approach similar to that shown in Equation 2 above).

3.7.4 Non-Major, Non-Local Industries

The CIM's and LCIM's allocation for non-labor expenditures associated with non-major, non-local industries reflects the following four-step process:

1. ***Estimate percentage of demand supplied by the 23 BOEM EIAs collectively:*** The allocation in the CIM and LCIM assumes that a fraction of the demand for commodities from non-major, non-local industries in the 23 BOEM EIAs is met by domestic production inside these EIAs collectively and that the remainder is met by either domestic production outside the EIAs (i.e., from the rest of state areas or other states) or foreign production. Using an IMPLAN model for all 23 EIAs combined, the regional purchase coefficient (RPC)[14] for all relevant commodities were obtained. These values indicate the proportion of total demand across the 23 EIAs collectively that is met by production within the 23 EIAs.[15] This proportion is referred to as $A_{EIA,i}$.
2. ***Estimate fraction of demand in the EIAs met by domestic imports and the fraction met by foreign imports:*** Demand across the 23 EIAs not met by production within the EIAs (1-RPC) is met by either domestic imports (domestic production outside the EIAs) or foreign imports. This proportion was calculated by setting up another IMPLAN model with a study region containing the entire US except for the combined EIA region ("NEUS"). From this model, it was possible to calculate domestic exports from the non-EIA US to the 23 EIAs collectively as the entirety of domestic exports reported by IMPLAN for the non-EIA US model (i.e. when the US is defined as two regions, domestic exports from one region are equal to domestic imports into the other region).

[14] The RPC for a given commodity represents the proportion of all local demands (industrial and institutional) for that commodity that is supplied locally (i.e., by the region to itself).

[15] Description of data elements in IMPLAN social account tables are available at: https://implanhelp.zendesk.com/hc/en-us/articles/115009674728-Understanding-the-Social-Accounts-Tables.

Using these data, the percentage of the EIAs' collective demand supplied by the non-EIA region was calculated as follows:

(4) $A_{NEUS,i} = I_{D,EIA,i}/TGD_{EIA,i}$

Where:

$A_{NEUS,i}$ = Fraction of demand for commodity *i* across the 23 EIAs met by the non-EIA portion of the U.S.

$I_{D,EIA,i}$ = Domestic imports of commodity *i* into the combined EIA region (i.e., the 23 EIAs combined), assumed to be equal to domestic exports of commodity *i* out of the non-EIA portion of the U.S.

$TGD_{EIA,i}$ = Total gross demand for commodity *i* in the combined EIA region

After determining the supply by the non-EIA region for demand in the combined EIA region, the remaining portion of unallocated demand must be met by foreign supply:

(5) $A_{ROW,i} = 1 - RPC_{EIA,i} - A_{NEUS,i}$

Where:

$A_{ROW,i}$ = Fraction of demand for commodity *i* across the 23 EIAs met by the rest of the world.

$RPC_{EIA,i}$ = Regional purchase coefficient for commodity *i* for the combined EIA region.

The spatial distribution across these initial three regions (the 23 EIAs collectively, NEUS, and ROW) allowed for the use of commodity flows in IMPLAN to more accurately define the bounds of how much demand in the combined EIA region is likely to be supplied locally in the EIA region, domestically in the rest of the US, and in the rest of the world.

3. ***Allocate supply from the non-EIA U.S. to the rest of state portions of each Gulf state and states not in the Gulf:*** After isolating the fraction of demand met by the non-EIA portion of the US, demand was further allocated to individual states (including rest-of-state areas in the Gulf), as represented in Equation 6.

(6) $A_{s,i} = G_{s,i} \times A_{NEUS,i}$

Where

$A_{s,i}$ = Fraction of demand for commodity *i* across the 23 EIAs met by state *s*,[16] and

$G_{s,i}$ = Fraction of non-EIA supply of commodity *i* to the 23 EIAs that is met by state *s*.

Because IMPLAN does not contain specific commodity flows from one region to another, it was not possible to precisely estimate $G_{s,i}$. In the absence of detailed trade flow data, the distribution of supply from the non-EIA U.S. to the ROS areas and the non-GOM states was approximated using the standard economic gravity equation:

(7) $X_{isg} = \frac{Y_{is}E_{ig}}{d_{sg}}$

Where:

X_{isg} = Sales of commodity *i* from state *s* to the Gulf region;

[16] For the Gulf states, state *s* refers to the rest of state area for the state.

Y_{is} = Production of commodity *i* in state *s*;

E_{ig} = Demand for commodity *i* in the Gulf region;

d_{sg} = Distance between state *s* and the production centroid of the Gulf, defined according to the BOE equivalents produced on individual leases between 2013 and 2017 (see Figure 6).

Because the standard gravity approach represented in Equation 7 does not constrain the values of X_{isg} such that the amount supplied to the Gulf is equal to demand, X_{isg} was normalized to derive an estimate of $G_{s,i}$ for inclusion in Equation 6:

$$(8) \quad G_{s,i} = \frac{X_{isg}}{\sum_s X_{isg}}$$

4. ***Allocate supply from the combined EIA area to individual EIAs:*** The final step involved distributing the total expenditures allocated to the EIAs collectively, as estimated in Step 1, to individual EIAs. This allocation was developed using a gravity-based approach similar to that outlined above in Step 3. However, the gravity equation was specified as follows:

$$(9) \quad X_{ieg} = \frac{Y_{ie} E_{ig}}{d_{eg}}$$

Where:

X_{ieg} = Sales of commodity *i* in from EIA *e* to the Gulf region.

Y_{ie} = Production of commodity *i* in EIA *e*;

E_{ig} = Demand for commodity *i* in the Gulf region;

D_{eg} = Distance between EIA *e* and the production centroid of the Gulf, defined according to the BOE equivalents produced on individual leases between 2013 and 2017.

The values from Equation 9 were then normalized similar to the procedure represented by Equation 8 to develop EIA-specific percentages that sum to 100 percent.

After implementing the steps above, a few adjustments were made to the resulting allocations. For two of the IMPLAN 536 commodities associated with non-major, non-local industries, natural gas plant liquids and fossil fuel electric power generation, IMPLAN does not have commodity trade flow data. For natural gas plant liquids, the CIM and LCIM apply the same spatial allocation as sector 20 (natural gas and crude petroleum). For fossil fuel electric power generation, the CIM and LCIM allocate expenditures in proportion to total fossil fuel power supply by county to account for the interconnected nature of the power grid.[17]

Because the above spatial allocations were completed using IMPLAN commodity flows, two adjustments were necessary to convert the commodity allocations to industry allocations to which industry multipliers could be applied. First, each commodity was assumed to be produced entirely by its corresponding industry. For example, IMPLAN Commodity 3178 "Adhesives" was assumed to be produced entirely by IMPLAN Industry 178 "Adhesives Manufacturing." Second, in some cases, the above approach may lead to allocation to regions with no industry production. In the cases in which the industry output multiplier is zero (i.e., there is zero production), the allocation was changed to zero to avoid assigning industry

[17] Generator-level fossil fuel production data were aggregated to the EIA-, ROS-, and State-level using US EIA Form EIA-923 at https://www.eia.gov/electricity/data/eia923/ and US EIA Form EIA-860 at https://www.eia.gov/electricity/data/eia860/index.html, both accessed August 7, 2019.

production to regions with no current industry production. The unallocated portion was then redistributed across the other EIAs (or ROS areas) in proportion to their current allocations.

3.8 Application of IMPLAN Multipliers

After estimating industry expenditures and allocating those expenditures to individual geographic areas and (for non-labor expenditures) industries, the CIM and LCIM apply multipliers to these expenditure values to estimate the output, value added, income, and employment impacts associated with those expenditures. These calculations are represented by the orange and green boxes shown near the bottom of Figure 4 above.

The multipliers used in the CIM and LCIM were obtained from the 2017 version of IMPLAN (IMPLAN 2017), the most recent version of IMPLAN available at the time of the models' development. IMPLAN 2017 includes data for 536 distinct industry sectors. For each of these industries, IMPLAN includes multipliers for direct, indirect, and induced economic impacts. Direct impacts are those directly related to industry expenditures, such as the employment of labor reflected in an industry's expenditures. Indirect and induced impacts, however, both represent secondary effects. Indirect economic impacts arise from changes in inter-industry purchases. For example, changes in direct expenditures on water transportation services result in indirect economic impacts on the various industries that provide inputs to water transportation suppliers, such as boat manufacturing, insurance, and boat maintenance. Induced economic impacts, in contrast, arise from workers in directly or indirectly affected industries spending their wages on goods and services (e.g., groceries, clothing, consumer electronics).

The approach specified here for estimating and applying multipliers from IMPLAN 2017 was designed to achieve three specific goals. First, to develop economic impact estimates that are as comprehensive and inclusive as possible, the approach included in the CIM and LCIM was designed to minimize leakage (i.e., economic impacts not captured due to trade flows outside the geographic area represented by an input-output multiplier). By its nature, leakage leads to the systematic underestimation of economic impacts, leaving policymakers and the public with an incomplete view of the economic impacts associated with an activity. Second, to provide insights into the distribution of economic impacts, the CIM and LCIM use multipliers that allow for the estimation of impacts with a relatively fine degree of spatial resolution, in particular at the sub-state level in the Gulf region. Third, and more practically focused than the other goals, the approach to applying multipliers was designed to be transparent, straightforward to implement, and easily updatable.

3.8.1 Types of Multipliers

The types of multipliers applied in the CIM and LCIM differ for OCS oil and gas activities for which the models distinguish between labor expenditures and non-labor expenditures and those activities for which the models do not make this distinction. As described in Section 3.4, the CIM and LCIM distinguish between labor and non-labor for four OCS oil and gas activities: (1) exploratory well drilling, (2) development well drilling, (3) non-productive well drilling, and (4) production O&M. For all other OCS oil and gas activities, the CIM and LCIM do not distinguish between labor expenditures and non-labor expenditures.

3.8.1.1 OCS Activities with No Distinction Between Labor and Non-labor Expenditures

For OCS oil and gas activities other than the four specified above, the CIM and LCIM apply industry multipliers directly from IMPLAN (with no adjustments) to estimate the economic impacts associated with industry expenditures. The industries associated with each activity are identified according to the approach described in Section 3.5 above. The multipliers taken from IMPLAN reflect the direct, indirect, and induced economic impacts associated with these activities.

3.8.1.2 OCS Activities with Separate Labor and Non-labor Expenditures

To estimate the economic impacts associated with activities for which the CIM and LCIM distinguish between labor expenditures and non-labor expenditures, the models apply two types of multipliers: labor income multipliers and industry multipliers. For the labor expenditures associated with these activities, the CIM and LCIM apply labor income multipliers obtained from IMPLAN. Before applying these multipliers, the models allocate labor expenditures based on the approach described above in Section 3.6.

Though the labor income multipliers from IMPLAN reflect the induced economic impacts associated with workers spending the income earned contributing to these activities, they do not capture the direct economic impacts associated with labor expenditures (e.g., the labor expenditures themselves directly reflect a certain amount of output). These direct economic impacts are also not captured in the CIM's and LCIM's calculation of economic impacts related to non-labor expenditures. To estimate the direct employment impacts associated with labor expenditures, the CIM and LCIM apply the ratio of employment to labor income as derived from IMPLAN for the industries associated with exploratory well drilling, development well drilling, non-productive well drilling and production O&M. This ratio was estimated separately for each of the four activities for which labor and non-labor expenditures are estimated separately and reflect the relative contributions of specific industries to each activity. These multipliers were derived based on data for the 23 EIAs combined. The CIM and LCIM distribute the direct employment impacts associated with labor expenditures in proportion to the spatial distribution of labor expenditures themselves.

The CIM and LCIM also estimate the direct output and value added impacts associated with labor expenditures. Assuming that the full cost of labor is reflected in the output value of each relevant industry, the CIM and LCIM apply an output multiplier of 1.0 to labor expenditures. Similarly, because value added is a component of output, the models also apply a direct output multiplier of 1.0 to labor expenditures. These direct output and value added impacts associated with these labor expenditures are likely to be realized at the location where the activity (i.e., well drilling or oil/gas production) occurs rather than where workers live. Therefore, the CIM and LCIM spatially allocate the direct value added and output impacts associated with labor expenditures using a similar approach as for non-labor expenditures. The CIM and LCIM spatially allocate the direct value added and output impacts associated with labor expenditures using the same spatial distribution as for non-labor expenditures with one adjustment: the models do not allocate any labor expenditures to the rest-of-world, as the direct labor expenditures occur entirely within the US. Instead, the CIM and LCIM redistribute any expenditures that would otherwise be allocated to the rest-of-world geographic area across all domestic geographic areas in proportion to each region's original allocation.

For the non-labor expenditures associated with the four activities identified above, the CIM and LCIM rely upon adjusted industry multipliers adapted from IMPLAN. Because the unadjusted multipliers taken directly from IMPLAN assume that a certain portion of an industry's expenditures are labor expenses paid to its workers (i.e., they reflect the production function for that industry), they are inconsistent with the goal of estimating economic impacts associated only with *non-labor* expenditures. Thus, IMPLAN's unadjusted industry multipliers do not provide accurate estimates of the economic impacts associated with *non-labor* expenditures. For example, if (hypothetically for the purposes of illustration) the offshore oil and gas industry spends $100 million on exploratory well drilling and 30 percent is labor expenditures and 70 percent is non-labor expenditures, IMPLAN's industry expenditure multipliers reflect a certain portion of the $70 million identified as non-labor expenditures as being spent on labor. Correcting for this issue requires adjustments to the direct, indirect, and induced industry expenditure multipliers in IMPLAN.

Adjustments to Indirect Impact Multipliers

Adjusting IMPLAN's indirect impact multipliers to reflect impacts of non-labor expenditures required a sector-specific accounting of labor in each industry's production function. Continuing with the example above, if the CIM or LCIM estimate $70 million in non-labor expenditures for a given industry and 40 percent of the industry's costs are labor, the (unadjusted) indirect impact multipliers in IMPLAN reflect $42 million in non-labor expenditures (60 percent of $70 million) rather than $70 million. From this example, it follows that IMPLAN's indirect industry expenditure multiplier for an industry reflects the multiplier impacts associated with its non-labor expenditures and the weighting of these expenditures in the industry's production function relative to labor:

(10) $$M_{p,i} = (1 - L)M_{n,i}$$

Where:

$M_{p,i}$ = IMPLAN's indirect impact multiplier for a given industry, given IMPLAN's production function for that industry;

L = Labor costs as a fraction of a given industry's costs per unit of output, as obtained from IMPLAN (approximated based on the labor income multiplier for an industry);

$M_{n,i}$ = Indirect impact multiplier associated with a given industry's non-labor expenditures.

Rearranging the terms in Equation 10, the adjusted indirect impact multipliers associated with non-labor expenditures only were estimated as follows:

(11) $$M_{n,i} = \frac{M_{p,i}}{(1 - L)}$$

Related to this equation, the CIM and LCIM follow a number of steps to estimate a reasonable value for the fraction of output that is labor income. As context, IMPLAN defines labor income as equal to the sum of employee compensation and proprietors' income. However, the value used for proprietors' income in IMPLAN reflects, among other components, the capital consumption allowance (CCA) as reported by sole proprietorships and partnerships for tax purposes. Because CCA is depreciation of capital and does not reflect true labor income as used in the CIM and LCIM, the models implement an adjustment to re-estimate proprietors' income by removing CCA.

1. First, for a given sector and geographic area represented in IMPLAN, this method estimates the amount of proprietor income that is not CCA using IMPLAN data in conjunction with BEA two-digit NAICS-level data for both total non-corporate CCA and nonfarm proprietors' income. For example, the pipeline transportation (Sector 413) corresponds to NAICS 486 (Pipeline transportation), or the two-digit NAICS category of Transportation and Warehousing (NAICS 48). BEA reported $45.5 billion in CCA and $63.8 billion in proprietor income in 2015 for NAICS 48 (i.e., 71.3 percent of proprietor income is CCA, and 28.7 percent is actual proprietor income) (BEA, 2018a and 2018b). IMPLAN reports proprietor income of $421 million in EIA TX-1 for Sector 413. The CIM and LCIM assume that the actual proprietor income is equal to the fraction of proprietor income that is not CCA (i.e., $421 million × 28.7 percent = $121 million). Because the BEA data are available only at the two-digit NAICS-level, this provides an

approximation of the ratio of CCA to proprietor income for the more detailed IMPLAN industry definitions.

2. Next, the CIM and LCIM calculate L, accounting for the ratio of CCA to PI developed in (1). For example, for Sector 413 in TX-1, the CIM and LCIM calculate labor income as the sum of employee compensation reported by IMPLAN ($17.5 million) and the value for proprietor income calculated in Step 1 above ($121 million), or $138 million total.
3. Finally, the CIM and LCIM divide labor income by output reported by IMPLAN to derive an estimate of L. For the example above (Sector 413 in TX-1), this calculation yields a value of 0.31 (i.e., $138 million in labor income / $443 million in output= 0.31).

The steps outlined above to calculate L are summarized by the following equation:

$$(12) \quad L = \frac{EC_I + PI_I(1 - CCA_B/PI_B)}{O_I}$$

Where:

EC_I = Employee compensation, reported by IMPLAN by sector and geographic area

PI_I = Proprietor income, reported by IMPLAN by sector and geographic area

CCA_B = Capital consumption allowance (CCA), reported by the corresponding BEA sector

PI_B = Proprietor income, reported by the corresponding BEA sector

O_I = Output, reported by IMPLAN by sector and geographic area

The LCIM applies the above formula subject to the following decision rules:

1. ***If proprietor income in IMPLAN or based on the method above is negative, set proprietor income equal to zero.*** Over the long run, we would not expect proprietor income to be negative; otherwise, proprietorships in an industry would not survive. We therefore assume that negative proprietor income values reflect a short-term downturn for proprietors in a given industry and geographic area.
2. ***Make no adjustment if the BEA data show that $\boldsymbol{CCA_B/PI_B}$ is less than zero.*** As described above, the purpose of the adjustment represented in Equation 12 is to remove the *portion* of proprietors' income that is CCA. However, if $\boldsymbol{CCA_B/PI_B}$is less than zero in the BEA data, proprietor income as represented in Equation 12 would *increase*.
3. ***Make no adjustment if the BEA data show that $\boldsymbol{CCA_B/PI_B}$ is greater than one while the IMPLAN data show positive proprietor income.*** When CCA is greater than proprietors' income in the BEA data, this suggests that the BEA data show negative proprietor income for the industry. If the IMPLAN and BEA data disagree with respect to the sign of proprietor income, we assume that the BEA data are not appropriately representative for adjusting the IMPLAN data for that industry.
4. ***Make no adjustment to the indirect multiplier if the adjusted value is negative***. If, after the above rules are applied, a specific industry in a geographic area results in a negative indirect multiplier, the CIM and LCIM use the original, unadjusted industry multiplier extracted from IMPLAN to avoid estimating negative indirect effects. Negative indirect impacts imply that additional expenditures for an industry result in a *reduction* in purchases of inputs from other industries, which is unrealistic. To avoid this, the CIM and LCIM use the original IMPLAN multiplier in such cases.

Adjustments to Induced Impact Multipliers

The multiplier adjustments for induced impacts account for the two types of impacts reflected in IMPLAN's induced impact multipliers. Specifically, these multipliers reflect (1) the impacts associated with workers in a *directly* impacted industry spending their wages and (2) the impacts associated with workers in *indirectly* impacted industries (i.e., up the supply chain from the directly affected industry) spending their wage income. The adjustments to IMPLAN's induced industry expenditure multipliers must eliminate the first of these effects, because it reflects *labor* expenditures rather than *non-labor* expenditures for a directly affected industry. The second of these (induced) impacts, however, arises from the indirect (i.e., upstream) effects associated with the expenditures of a directly affected industry. Because, as described above, the IMPLAN multipliers underestimate indirect effects when estimating impacts for non-labor expenditures only, the portion of the induced impact multiplier that reflects the second impact identified above must be increased.

The below equation reflects both of these adjustments. The numerator subtracts the induced impacts associated with workers in a directly impacted industry spending their wages ($L \times M_{l,d}$) from IMPLAN's multiplier for the total induced impacts associated with the industry ($M_{p,c}$). Thus, the numerator represents the portion of IMPLAN's induced impact multiplier associated with workers in indirectly affected industries spending their wage income. Without any further adjustment, the numerator would lead to underestimation of impacts related to non-labor expenditures because it does not account for the fact that IMPLAN's multipliers assume that a fraction of industry expenditures are on labor. Dividing this value by the denominator adjusts for this in much the same way as dividing by *(1- L)* in Equation 11 scales IMPLAN's indirect impact multipliers to calculate the multipliers associate with an industry's non-labor expenditures. The value for labor costs as a fraction of output (*L*) used in the formula is subject to the same adjustment and decision rules as used for the indirect multipliers, as described above.

(13) $$M_{n,c} = \frac{M_{p,c} - (L \times M_l)}{(1 - L)}$$

Where L is as defined above and:

- $M_{n,c}$ = Induced impact multiplier associated with an industry's non-labor expenditures;
- $M_{p,c}$ = IMPLAN's induced impact multiplier for a given industry, given IMPLAN's production function for that industry;
- M_l = IMPLAN's labor income multiplier for a given geographic area.

Adjustments to Direct Impact Multipliers

For direct impacts related to non-labor expenditures, the direct multiplier values for employment and labor income were set to zero. Because non-labor expenditures involve no labor, these expenditures result in no direct employment or labor income impacts. The direct value added multiplier values were also adjusted to reflect the fact that the unadjusted multipliers from IMPLAN reflect a certain amount of labor. In addition, because they reflect some expenditures on labor, the non-labor portion of direct value added associated with non-labor expenditures is underestimated when applying IMPLAN's direct value added multipliers to non-labor expenditures. To account for both of these distortions, the direct value added multipliers applied to non-labor expenditures were adjusted based on the following equation:

(14) $$AM_{d,v} = \frac{\left(M_{d,v} - L\right)}{(1 - L)}$$

Where L is as defined above and:

$AM_{d,v}$ = adjusted direct value added multiplier;

$M_{d,v}$ = direct value added multiplier as obtained from IMPLAN;

The numerator of the above equation removes labor from the direct value added multiplier. Without any further adjustment, the numerator would lead to underestimation of impacts related to non-labor expenditures because it does not account for the fact that IMPLAN's multipliers assume that a fraction of industry expenditures are on labor. Dividing this value by the denominator adjusts for this in much the same way as dividing by $(1- L)$ in Equation 11 scales IMPLAN's indirect impact multipliers to calculate the indirect multipliers associate with an industry's non-labor expenditures. The value for labor costs as a fraction of output (L) used in the above formula is subject to the same adjustment and decision rules as used for the indirect multipliers, as described above.

3.8.2 Spatial Resolution of Multipliers

The spatial resolution of the economic multipliers applied in the CIM and LCIM varies between the Gulf region and the rest of the US, with more spatial detail for the Gulf multipliers. Outside the five states that border the Gulf (i.e., Texas, Louisiana, Mississippi, Alabama, and Florida), the CIM and LCIM estimate economic impacts at the state level. In contrast, for each of the five states in the Gulf region, the models estimate economic impacts for each EIA in the state (see Figure 2 above) and the rest-of-state area (i.e., the portion of the state that is not part of any EIAs).

3.8.2.1 Gulf of Mexico Region

To estimate economic impacts for each EIA and rest-of-state area in the Gulf region, the CIM and LCIM use a tailored multiplier approach designed to provide a high degree of spatial detail (EIA-specific results) while minimizing leakage in the results. The specific steps in this approach are as follows:

1. ***Estimate impacts for the entire GOM combined:*** The CIM and LCIM first estimate direct, indirect, and induced economic impacts for the entire GOM based on multipliers derived from IMPLAN for all five Gulf states collectively (i.e., Texas, Louisiana, Mississippi, Alabama, and Florida as a single region). The total impacts generated from these multipliers represent the basis for the impact estimates for each EIA and rest-of-state area.

2. ***Develop preliminary impact estimates by EIA and rest-of-state area:*** In parallel with generating the values from Step 1, the CIM and LCIM also estimate economic impacts for each EIA and rest-of-state area individually, using multipliers specific to each EIA and rest-of-state area.

3. ***Allocate GOM-wide impact estimates:*** Based on the distribution of impacts from Step 2, the CIM and LCIM allocate the economic impacts for the Gulf as a whole (from Step 1) to individual EIAs and rest-of-state areas. Specifically, the models allocate the direct economic impacts for the Gulf area to individual EIAs and rest-of-state areas in proportion to the direct economic impacts estimated for each EIA and rest-of-state area, and allocate the indirect and induced economic impacts for the Gulf to individual EIAs and rest-of-state areas in proportion to the indirect and induced economic impacts estimated for each EIA and rest-of-state area. For example, if EIA TX-3 accounts for 20 percent of the direct economic impacts estimated across each of the EIA and rest-of-state analyses, 30 percent of the indirect impacts estimated across the individual EIA and rest-of-state analyses, and 32 percent of induced impacts, TX-3 is allocated 20 percent of the direct impacts estimated from the initial Gulf-wide analysis in Step 1 above, 30 percent of the indirect impacts, and 32 percent of the induced impacts.

The CIM and LCIM use this three-step approach to generate EIA- and rest-of-state-specific results for labor expenditure impacts, non-labor expenditure impacts, and impacts associated with activities for which the LCIM does not distinguish between labor expenditures and non-labor expenditures.

3.8.2.2 Rest of U.S. Region

For the rest-of-US region, the CIM and LCIM employ a slightly more complex approach to better account for trade flows between states. Because the rest-of-US region is much larger than the Gulf region, it would be too simplistic to apply the process outlined above to the rest of the US. Instead, the CIM and LCIM use the following method:

1. ***Estimate impacts for entire rest-of-US region:*** apply rest-of-US multipliers to the combined direct expenditures in the rest-of-US to estimate direct, indirect, and induced economic impacts.
2. ***Develop preliminary impact estimates by state for every rest-of-US state:*** apply state-specific multipliers to estimate direct, indirect, and induced impacts in each state.
3. ***Calculate the residual between the total indirect and induced impacts in the rest-of-US and the sum of the state-level induced and indirect impacts:*** calculate the difference between the indirect (induced) impacts from Step 1 and the sum of the indirect (induced) impacts from Step 2. This residual is assumed to be the total leakage unaccounted for by state-specific multipliers applied in Step 2.
4. ***Allocate the residual indirect and induced effects according to economic gravity:*** allocate the residual indirect and induced effects from Step 3 to each state, weighted by the OCS-related expenditures in the *source* state from which the activity originates, the size of the economy of the recipient state, and the inverse of the distance between these two states. Specifically, the CIM and LCIM apply the following steps:
    a. ***Estimate the total leakage originating from each source state.*** For example, if Oklahoma accounts for 10 percent of the total direct effects (summing across industries) in the rest-of-US area, the CIM and LCIM assume that 10 percent of the residual economic impacts (estimated in step 3) are associated with OCS-related expenditures in Oklahoma (i.e., 10 percent of the additional economic impacts occur *outside* of Oklahoma, but are indirect and induced effects related to OCS-related expenditures *in* Oklahoma). Continuing with this example, if the total residual is $500 million, the total leakage from Oklahoma to all other states is estimated to be $50 million.

    b. ***Estimate the total leakage to each recipient state using gravity:*** For the leakage associated with each source state (e.g., the $50 million in leakage associated with OCS-related expenditures in Oklahoma above), estimate the flow of economic impacts from the source state to every other recipient state in the rest-of-US. area using gravity. For example, the CIM and LCIM estimate the flow of indirect effects *from* Oklahoma *to* every other state. The models calculates X_{ser} to determine the fraction of the $50 million that is allocated to each recipient state from a given source state, as represented in the equation below:

    (15) $$X_{ser} = \frac{Y_r R_{es}}{d_{sr}}$$

    Where:

    X_{ser} = Economic impact *e* from source state *s* to recipient state *r*, where *e* represents either indirect or induced effects;

    Y_r = Size of economy (total output) in recipient state *r*;

R_{es} = Residual economic impact *e* originating in source state *s*;

d_{sr} = Distance between source state *s* and recipient state *r*.

The resulting values of X_{ser} are then subjected to a normalization process similar to that presented in Equation 2 to determine the proportion of the total economic impacts that are distributed to each recipient state.

c. ***Repeat the allocation for all source states and calculate the total residual allocation:*** apply Steps a and b above to every source state and sum results by recipient state.

5. ***Calculate total allocation:*** calculate the total allocation to each state as the sum of the results from the local economic impacts (Step 2) above and the results of the total residual allocated to each state (Step 4).

4 Impacts Related to Government OCS Revenues

4.1 Introduction

As indicated in Chapter 1, the Cumulative Impacts Model (CIM) and Lifecycle Impacts Model (LCIM) estimate the fiscal and economic impacts associated with Outer Continental Shelf (OCS) revenues collected by the federal government—royalties, bonus bids, and rents. When users enter scenario data via the CIM's exploration and development (E&D) spreadsheet or the LCIM's detailed scenario spreadsheet, these revenues are directly provided by the user, by year and revenue type (royalties, bonuses, and rents). In contrast, when users enter scenario data with the LCIM's streamlined leasing scenario interface, the LCIM generates its own estimates of royalties and rents by year, though users still directly provide estimates of bonuses. In addition, for each revenue type, both the CIM and LCIM distinguish between 8(g) revenues and non-8(g) revenues. For forward-looking analyses, the models allocate all OCS government revenues to the federal government, state governments, and coastal political subdivisions in accordance with the allocation rules codified in federal regulations, as illustrated in Figure 7. For historical analyses (CIM only), the user enters the distribution of OCS revenues across these government entities. Based on the allocation of OCS revenues to individual jurisdictions, the CIM and LCIM use IMPLAN multipliers to estimate the economic impacts associated with government expenditures of these revenues. The specific economic impacts estimated by the models include changes in output, value added, income, and employment.

The spatial resolution of CIM and LCIM results related to government OCS revenues is consistent with the models' spatial resolution for impacts related to industry expenditures. Specifically, the models present these estimates by economic impact area (EIA) (for the Gulf of Mexico [Gulf] region), the rest-of-state area for each state where EIAs are located (i.e., states on the Gulf), and at the state level for areas outside the Gulf of Mexico. Related to the allocation of OCS revenues, the CIM and LCIM capture the revenue sharing provisions of the Gulf of Mexico Energy Security Act (GOMESA) and section 8(g) of the Outer Continental Shelf Lands Act (OCSLA).

The sections that follow present the details of the models' approach for estimating the fiscal and economic impacts associated with OCS government revenues. The chapter begins by describing the approach for estimating OCS government revenues in the two models. Following this discussion, the chapter describes how the CIM and LCIM allocate these OCS government revenues to specific jurisdictions (i.e., the federal government, state governments, and EIAs). This approach reflects both 8(g) and GOMESA revenue sharing provisions. The chapter then describes how the CIM and LCIM use IMPLAN multipliers to estimate the economic impacts associated with the expenditure of OCS government revenues. This chapter does not present the CIM's and LCIM's approach for assessing the impacts of taxes on corporate profits and dividends. This information is presented in Chapter 5.

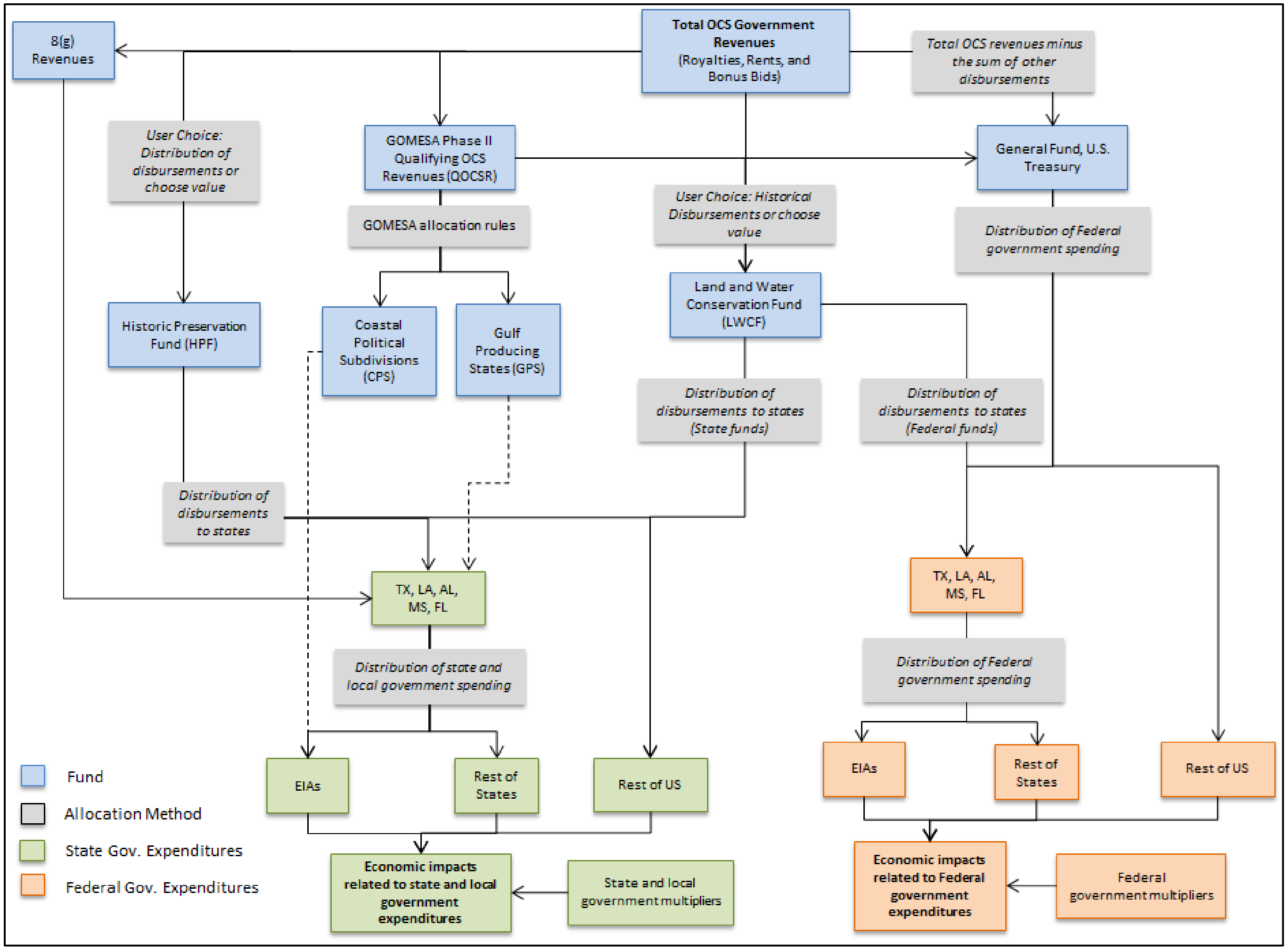

Figure 7. Schematic of CIM and LCIM approach for estimating economic and fiscal impacts related to OCS revenues.

4.2 Estimation of OCS Government Revenues

The specification of OCS revenues is critical to estimating the economic and fiscal impacts of such revenues. The CIM and LCIM apply different approaches for specifying OCS revenues due to differences in the analytic context of each model. The CIM relies exclusively on OCS revenue data entered by the user. For retrospective analyses, these data reflect actual OCS revenue collections. For prospective analyses, the CIM relies on user-provided data that reflect the user's assumptions regarding production on pre-existing leases with specific royalty provisions and production on new leases with more uncertain royalty conditions.

The specification of OCS government revenues in the LCIM varies depending on how model users enter scenario data into the model. When users enter scenario data with the detailed leasing scenario spreadsheet, all estimates of royalties, rents, and bonus bids are provided directly by the user by year. Under these circumstances, the LCIM performs no additional calculations to generate estimates of OCS revenues. However, when model users enter scenario data through the streamlined leasing scenario interface, the model internally estimates royalties and rents, though estimates of bonuses are still provided directly by the model user. To estimate the royalties associated with leasing scenarios entered through the streamlined interface, the LCIM applies the following equation based on data entered by the user:

$$(16)\quad Y_t = \left[\left(Q_{o,t} \times P_{o,t}\right) + \left(Q_{g,t} \times P_{g,t}\right)\right] \times y_r$$

Where:

Y_t = Royalties in year t;

$Q_{o,t}$ = Quantity of oil produced on the lease or group of leases in year t;

$P_{o,t}$ = Price of oil in year t;

$Q_{g,t}$ = Quantity of natural gas produced on the lease or group of leases in year t;

$P_{g,t}$ = Price of gas in year t, and

y_r = Royalty rate.

Both $Q_{o,t}$ and $Q_{g,t}$ are entered as a lump sum by water depth category via the streamlined scenario input interface. The model allocates these production estimates over time according to the distributions described in Appendix A. The LCIM includes default values, by year, for $P_{o,t}$ and $P_{g,t}$, though users have the flexibility to modify these values as they see fit by scenario. The model also includes default royalty rates (y_r) by water depth, though the user may modify these values as well for a given scenario.

To estimate the rental payments associated with individual leasing scenarios entered into the model through the streamlined user interface, the LCIM assumes that lessees pay rent on a lease or group of leases from the time of lease issuance through the year immediately before oil and/or gas production commences. The model's approach for calculating these rental payments is as follows:

$$(17)\quad R_t = N \times a \times r_a$$

Where:

R_t = rental payments in year t, where t is any year prior to the commencement of production;

N = number of leases;

a = acres per lease, and

r_a = annual rent per acre.

For leasing scenarios involving groups of leases, the number of leases (*N*) is provided by the user. The LCIM includes default values for both the acreage per lease (*a*) and rent per acre (r_a), though model users may change the values of both of these variables for a given leasing scenario.

To accurately estimate the economic impacts associated with all three types of OCS revenues, the LCIM must allocate these revenues over time. When users enter scenario data via the detailed scenario input spreadsheet, they provide this information directly. For scenarios entered with the streamlined leasing scenario interface, the LCIM applies the following assumptions:

- ***Bonuses***: The LCIM assumes that all bonuses are paid the year of lease issuance, as provided by the model user.
- ***Rents***: As described above, the LCIM estimates rent by year for each year prior to the commencement of oil/gas production. After production begins, rent on a lease or group of leases is assumed to be zero.
- ***Royalties***: For a given water depth category, royalties are paid during each year of production (assuming a royalty rate greater than zero). The LCIM's distribution of royalties over production years is proportional to sales revenues across these same years.

4.3 Spatial Allocation of OCS Government Revenues

The CIM's and LCIM's allocation of OCS government revenues among the federal government, state governments, and (in the case of GOMESA) coastal political subdivisions (aggregated to EIAs) is consistent with the revenue-sharing provisions of the individual statutes that govern the disbursement of OCS revenues. A thorough representation of these provisions is important for ensuring that the CIM and LCIM are accurate in their estimation of the magnitude and distribution of economic and fiscal impacts. The sections that follow present the methods applied by the CIM and LCIM for estimating and allocating revenues subject to GOMESA and the Section 8(g) provisions of OCSLA, as well as OCS revenues disbursed through the Historic Preservation Fund (HPF) and the Land and Water Conservation Fund (LWCF).

4.3.1 GOMESA Phase II Revenue Allocation

Phase II of GOMESA revenue sharing began in Fiscal Year 2017, expanding the definition of Qualified OCS Revenues (QOCSR) to include revenues generated from leases issued after December 20, 2006, in the 181 Call Area or in 2002–2007 in Gulf planning areas subject to withdrawal or moratoria restrictions. Phase II also includes an annual revenue sharing cap of $500 million through 2055 applied to the four Gulf producing states, their coastal political subdivisions, and the LWCF.[18] The cap does not apply to qualified revenues associated with areas included in GOMESA Phase I.

The CIM and LCIM include a detailed accounting of the collection and disbursement of revenues shared under GOMESA Phase II. All bonus bids, rents, and royalties associated with leases sold after the enactment of GOMESA, excluding such revenues collected on leases subject to Section 8(g) of OCSLA, comprise QOCSR, which are shared with Gulf producing states, the LWCF, and Coastal Political Subdivisions. The CIM (when used for prospective analyses) and LCIM account for GOMESA Phase II by first projecting total Qualified OCS Revenues (QOCSR) and then distributing revenues according to the regulatory criteria summarized in Table 7 below. The models differ, however, in how they project QOCSR.

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[18] The 2017 Tax Cuts and Jobs Act modified the Phase II cap for fiscal years 2020 and 2021. Because revenues subject to GOMESA are unlikely to approach the cap during these years, this temporary change to the cap is not incorporated into the CIM or LCIM.

4.3.1.1 CIM Projection of QOCSR from GOMESA leases

For backward-looking (retrospective) analyses, the CIM uses estimates of QOCSR entered by the model user, as obtained from the Office of Natural Resources Revenue (ONRR). For forward-looking analyses, however, model users have the option of entering their own projections (within the E&D spreadsheet) or allowing the model to generate its own estimates of GOMESA revenues (based on the royalty, rent, and bonus bid projections included in the E&D spreadsheet described in Chapter 2).

When users elect for the CIM to generate its own estimates of GOMESA revenues, the model relies on separate accountings of royalties, rents, and bonus bids to project total QOCSR. All new non-8(g) bonus bids beginning in FY2017 in the Central Gulf and Western Gulf are included in QOCSR because all new non-8(g) leases in these areas are GOMESA leases.[19] However, bonus bids are provided by the model user for the Gulf as a single region. To estimate bonus bids associated with GOMESA, the CIM therefore must distinguish between bonus bids on leases in the Eastern Gulf, most of which is not subject to GOMESA, and leases in the Central and Western Gulf. Because bonus bids are just a small fraction of OCS revenues and most leasing activity occurs in the Central Gulf and Western Gulf, the CIM assumes that all bonus bids are in the Central and Western Gulf but includes an option for the user to change the percentage of bonus bids associated with Eastern Gulf leases (e.g., from a default of zero to a percentage that the user deems appropriate). The CIM allocates the portions of bonus bids set aside for state governments and coastal political subdivisions using the criteria summarized below in Table 7.

For forward-looking analyses, CIM users provide production and royalties for the Gulf as a single region as inputs but (when generating its own estimates of QOCSR) the CIM must predict the proportion of production (and royalties) from GOMESA leases. To project the allocation between GOMESA and non-GOEMSA production (and royalties), the CIM estimates non-GOMESA, non-8(g) production, and then takes the difference between total projected production and non-GOMESA, non-8(g) production to be GOMESA and 8(g) production. The CIM assumes that GOMESA and 8(g) royalties are proportionate to the estimate of combined GOMESA and 8(g) production. The CIM then subtracts 8(g) royalties (entered by the user through the E&D spreadsheet) to estimate the total GOMESA royalties. More specifically, the CIM estimates future production on non-GOMESA, non-8(g) leases separately for oil and gas by (1) estimating a general reserve depletion rate across the lifespan of the typical lease, (2) identifying existing non-GOMESA, non-8(g) leases, (3) applying the reserve depletion function specified in step 1 to existing non-GOMESA, non-8(g) leases, (4) calculating the difference between total GOM production and production on existing non-GOMESA, non-8(g) production, and (5) estimating the portion of production in Step 4 that is subject to GOMESA (and 8(g)). The details of each of these steps are as follows:

1. ***Estimate reserve depletion rate across all leases:*** The CIM's inferences regarding the distribution between GOMESA production and non-GOMESA production reflect the average reserve depletion rate over the lifespan of Gulf leases. Using data for leases that have either expired or produced for at least 30 years, the CIM accounts for the relationship between the amount of production remaining on a lease and the total production in any given year. Based on these data, it is possible to calculate the proportion of total remaining reserves produced by a lease in a given year at each level of remaining reserves. Extending this analysis to include the lifespan of each lease (i.e., until there is zero percent of reserves remaining) results in the relationship in Figure 8 below. For example, the figure shows that a lease with apporximately 4 percent of its original reserves remaining in a given year produces 18 percent of those remaining reserves that year. Overall, the figure shows that annual production as a *percent* of remaining reserves increases over time as *total* remaining reserves declines.

[19] By definition, a lease cannot be subject to both 8(g) and GOMESA revenue sharing.

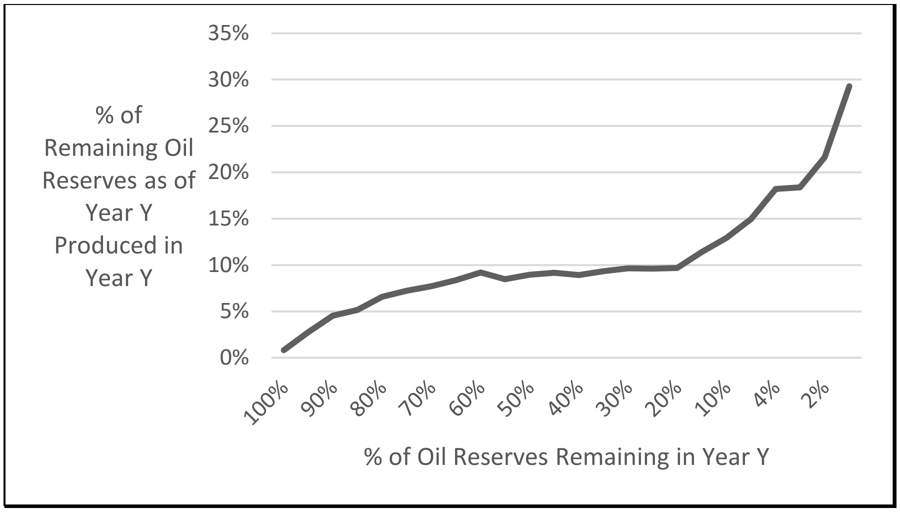

Figure 8. Percent of remaining oil reserves produced by percent of original reserves remaining.

2. ***Identify existing non-GOMESA, non-8(g) leases and allocate reserves to leases:*** Applying the information from Step 1 to existing non-GOMESA, non-8(g) leases requires (1) identification of these leases from BOEM data and (2) estimation of the reserves associated with each lease identified. With respect to the former, all leases sold before 2007 are assumed to be non-GOMESA leases. A lease is identified in the BOEM data if it is an 8(g) lease. Estimating reserves for each of these leases is complicated by the fact that reserve data are available only at the field level and one field can include multiple leases. To allocate the reserves on a given field to the leases on that field, reserves (original and current) are assumed to be distributed uniformly across all active leases in a field.[20]
3. ***Apply reserve depletion rate to existing non-GOMESA, non-8(g) leases to project future production:*** After identifying existing non-GOMESA non-8(g) leases, each lease's current level of remaining reserves was calculated to determine its position on the reserve depletion curve defined in Figure 8 above. To determine the current percent of remaining reserves, year 2016 reserves were divided by original oil reserves.[21] The current level of reserves defines each lease's placement on the horizontal axis of Figure 8, and the corresponding reserve depletion rate on the vertical axis, when combined with current reserves, defines the lease's production for that year.[22] For example, if an existing non-GOMESA, non-8(g) lease had 10 million barrels (MMbbl) of original reserves and 2 MMbbl of current reserves, this lease is assumed to have 20 percent of reserves remaining (2 MMbbl/10 MMbbl). This lease is projected to produce 10 percent of its remaining reserves, or 0.2 MMbbl (0.10 × 2 MMbbl), and will now have 18 percent of its reserves remaining (2.0 MMbbl–0.2 MMbbl)/10 MMbbl)) the following year. Carrying this

[20] For this analysis, "active" is defined to mean that the current year is between a lease's effective date and expiration date.

[21] The year 2016 was the most recent year for which data were available during the model's development, accessed at https://www.data.boem.gov/Main/FieldReserves.aspx on January 8, 2019.

[22] Functionally, we define a step function with 5 percentage point intervals, and assign a production rate to all leases with remaining reserves that fall within each 5-point range. For example, we estimate that all leases with *between* 20 and 25 percent of reserves remaining also produce 10% of remaining reserves.

approach forward through 2035, Figure 9 shows the projected decline of reserves over time after summing non-GOMESA non-8(g) lease reserves by planning area.

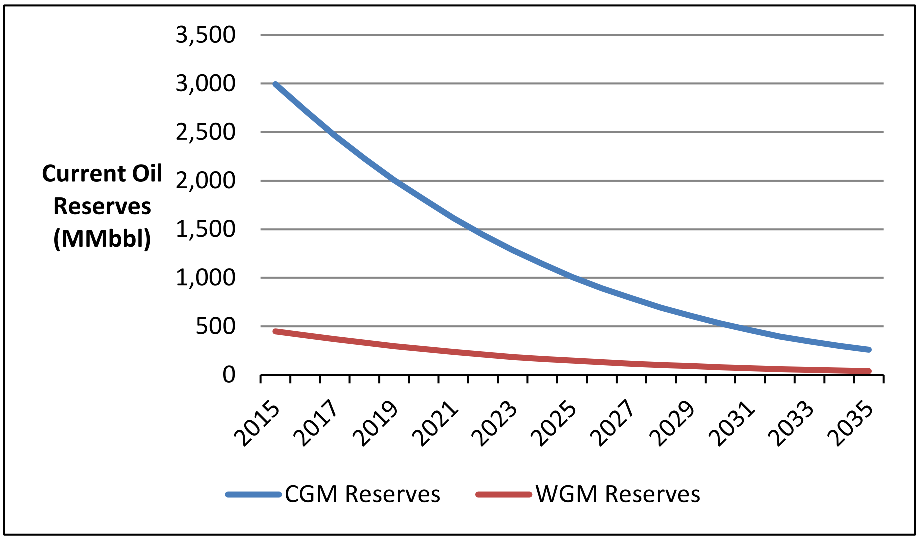

Figure 9. Non-GOMESA, non-8(g) projected decline in oil reserves.

4. ***Calculate the difference between total GOM production and production on existing non-GOMESA, non-8(g) leases.*** After projecting future production on existing non-GOMESA, non-8(g) leases, the CIM calculates the difference between total production (as provided by the CIM user) and production on existing non-GOMESA, non-8(g) leases as estimated in Step 3. This value reflects GOMESA production, 8(g) production, and any non-GOMESA production on new leases.
5. ***Calculate royalties on GOMESA and 8(g) leases combined:*** Of the production estimated in Step 4, the vast majority is likely to be in the Central Gulf and Western Gulf—and therefore subject to GOMESA. Though new leasing is possible in the Eastern Gulf following the end of the existing moratorium, significant investment to support production has already been made in the Central and Western Gulf. Thus, as a default, the CIM assumes that all production on non-8(g) leases issued after FY 2017 (i.e., the result of Step 4 above) is on GOMESA leases. The CIM, however, allows users to enter their own assumptions regarding the percentage of production on non-8(g) post-FY 2017 leases that is not subject to GOMESA (i.e., in the Eastern Planning Area). The CIM assumes that royalties are distributed between (1) non-GOMESA leases and (2) the sum of GOMESA and 8(g) leases combined in the same proportion as production.
6. ***Subtract 8(g) royalties:*** After distributing royalties between the two groups estimated at the end of Step 5, the CIM finally subtracts the user-entered 8(g) royalties from the value for the second group (i.e., combined GOMESA and 8(g) royalties). This yields the model's estimate of GOMESA royalties.

The CIM uses the process specified above to project the distribution between GOMESA and non-GOMESA production and royalties for any scenario.[23]

[23] We considered whether prices might impact original reserves (i.e., a large price increase might increase the amount of economically recoverable reserves). However, we found a very small statistically significant relationship between oil price and original oil reserves, and no statistically significant relationship between gas price and original

CIM users also provide rental payments as an input to the model through the cumulative E&D spreadsheet. Though the distribution of future rental payments between non-GOMESA and GOMESA leases is uncertain, the CIM (when developing its own estimates of QOCSR) approximates this distribution based on the characteristics of current rent-paying non-GOMESA leases and the typical production trajectory of BOEM leases in the Gulf . Similar to the above approach for estimating GOMESA royalties, the CIM estimates GOMESA rental payments for a given year as the difference between total non-8(g) rental payments (provided by the CIM user) and rental payments on existing non-GOMESA, non-8(g) leases. Rental payments on existing non-GOMESA, non-8(g) leases were estimated based on lease-specific data available from the BOEM Data Center.[24] The CIM assumes that all leases with an effective date before 2007, no expiration date, and no historical production are non-GOMESA leases with ongoing rental payments.[25] Leases identified as 8(g) leases were also excluded. Annual rental payments on these leases were estimated based on the lease-specific rental rate per acre and lease area in acres included in the BOEM data. Based on the issuance date of each lease and the 75th percentile for the time between lease issuance and the commencement of production on a lease (based on all producing leases in the Gulf, not just non-GOMESA leases), the first production year for each existing rent-paying non-GOMESA, non-8(g) lease was projected. For example, if an existing non-GOMESA, non-8(g) lease was issued in 2005 and year 15 is the 75th percentile for the first production year on a lease, the lease is assumed to continue paying rent until 2019. The 75th percentile was used for the time before production instead of the average because the non-GOMESA, non-8(g) leases still paying rent have been in place for more than a decade. The fact that these leases are not producing (and therefore still paying rent) suggests that the prospects for these leases are lower than average.

Applying this approach to every existing rent-paying non-GOMESA, non-8(g) lease, the decline in the number of such leases was projected over time. Rents on non-GOMESA, non-8(g) leases are assumed to decline in direct proportion to the number of non-GOMESA, non-8(g) leases. The CIM assumes that the residual amount (i.e., total rental payments less this amount) is subject to GOMESA or 8(g). The CIM then removes total 8(g) rental payments entered by the user to derive the total GOMESA rental payments. Though this approach does not capture potential rental payments on new leases in the Eastern Gulf , which would not be subject to GOMESA, rents on these leases are likely to be minimal for the reasons described above. The model user, however, has the option of specifying the percentage of the residual amount described above that is associated with leases in the Eastern Gulf.

4.3.1.2 LCIM Projection of Qualified OCS Revenues (QOCSR) from GOMESA leases

The methods used by the LCIM to estimate QOCSR differ from those described above for the CIM because the LCIM reflects new leasing activity only. Unlike the CIM, the LCIM does not capture economic and fiscal impacts for both existing leases and new leases. The LCIM therefore does not need to consider the production trajectory of *existing* leases over time, making the estimation of QOCSR much simpler than in the CIM.

To estimate QOCSR associated with a lease or lease sale, the LCIM applies one approach when users enter leasing scenario data through the detailed leasing scenario spreadsheet, in which data are entered for each year of the lease term (see Chapter 2), compared to the model's streamlined leasing scenario input

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gas reserves. Because most oil and gas has already been produced from non-GOMESA leases (and there are no more new non-GOMESA leases), it is more likely for price changes to affect newer GOMESA leases.

[24] BOEM. Lease Data. Accessed at: https://www.data.boem.gov/Main/Leasing.aspx

[25] All but two of the leases that match these criteria are included in "unit agreements" which consolidate multiple leases for development and production purposes. As a result, some of these leases may have stopped paying rent after production activities began on a separate lease included in the unit agreement. To the extent that these leases have stopped paying rents due to the terms of unit agreements, the CIM will overestimate non-GOMESA rents.

screen. When users provide data via the detailed leasing scenario spreadsheet, the spreadsheet itself will include annual estimates of QOCSR. In this situation, the LCIM performs no additional calculations to estimate QOCSR.

When users instead provide scenario data through the streamlined leasing scenario input screen in the LCIM, the model uses two different methods for estimating QOCSR: one for single lease analyses and one for multiple lease analyses (i.e., lease sales or National OCS Program scenarios). In both cases, the LCIM accounts for the GOMESA provision stating that revenues generated from leases subject to 8(g) are excluded from QOCSR. When the user-defined scenario is for a single lease, the user must indicate whether the lease is subject to 8(g). If the lease is not subject to 8(g), the model requires the user to indicate whether the lease is subject to GOMESA. For a lease that is not subject to 8(g) but is subject to GOMESA, 100 percent of the OCS revenues associated with that lease are QOCSR. On all other leases where these two conditions are not met, QOCSR is assumed to be zero.

For analyses of lease sales or National OCS Program scenarios, the LCIM follows a slightly different approach for estimating QOCSR. For these scenarios, the LCIM's streamlined leasing scenario interface prompts users to indicate (1) the percentage of leases by water depth that are subject to 8(g) and (2) the percentage of non-8(g) leases by water depth subject to GOMESA. Using this information, the LCIM estimates QOCCSR as follows:

$$(18) \quad QOCSR_t = \sum_d \left[Rev_{d,t} \times (1 - e_d) \times G_d \right]$$

Where:

$QOCSR_t$ = QOCSR for year t.

$Rev_{d,t}$ = oil and gas sales revenues associated with leases for water depth d and year t.

e_d = the percent of leases in water depth d subject to 8(g).

G_d = the percent of non-8(g) leases in water depth d subject to GOMESA.

The LCIM includes default values for e_d, though users may modify these values on a scenario-specific basis. Similarly, the LCIM assumes that G_d is 100 percent for all water depths, but users may enter their own assumptions for a given scenario.

4.3.1.3 Revenue allocation of QOCSR

After developing an annual estimate of total QOCSR, the CIM and LCIM distribute OCS revenues according to the allocation scheme presented in Table 7 below.

Table 7. Summary of GOMESA Phase II Revenue Allocation

Percent of Total QOCSR	Recipient of Funds	Revenue Allocation	Expenditure Allocation in LCIM
50%	General Fund of the US Treasury	N/A (100% to General Fund)	Revenues distributed spatially according to IMPLAN federal government demand to EIAs, rest-of-state areas, and non-GOM states.
12.5%	Land and Water Conservation Fund (LWCF)	N/A (100% to LWCF)	Revenues distributed to states in proportion to historical disbursements, then to EIAs, rest-of-state areas according to IMPLAN state and federal government demand.
30%	Gulf Producing States (AL,LA, MS, and TX)	Revenues distributed proportionally to the total inverse distance to historical lease sites[1]	Revenues disbursed as government expenditures according to IMPLAN state government demand across EIAs and rest-of-state areas.
3.75%	Coastal Political Subdivisions	Revenues distributed proportionally to the total inverse distance to historical lease sites[1]	Revenues aggregated to EIA-level, and distributed across education, non-education, and investment spending according to IMPLAN state and local government demand.
1.875%	Coastal Political Subdivisions	Revenues distributed proportionally to population[1]	
1.875%	Coastal Political Subdivisions	Revenues distributed proportionally to coastline length[1]	

Note: The CIM and LCIM use the same allocation proportions as disbursed by ONRR for FY2017.

The CIM and LCIM incorporate several additional considerations to ensure that they accurately measure the disbursement of revenues. First, revenue sharing is capped at $500 million.[26] If QOCSR are greater than $1 billion, additional funds are allocated to the general fund of the US Treasury. Second, consistent with GOMESA provisions, no state can receive less than 10 percent of the state share (inclusive of funds disbursed to each state government and the coastal political subdivisions within each state). If the allocation scheme in Table 7 results in an allocation of less than 10 percent to a state, that state's allocation is changed to 10 percent, and the remaining 90 percent of the state share is reallocated to the other states in the same proportion.[27]

4.3.2 8(g) Revenue Estimation and Allocation

Section 8(g) of OCSLA establishes that 27 percent of all revenues collected within the 8(g) zone (three nautical miles seaward of state waters) are distributed to the states. Similar to GOMESA revenues, the estimation and allocation of 8(g) revenues differs between the CIM and LCIM due to differences in their design and data input structure, as described in detail below.

[26] As indicated in a previous footnote, the 2017 Tax Cuts and Jobs Act modified the Phase II cap for fiscal years 2020 and 2021. Because revenues subject to GOMESA are unlikely to approach the cap during these years, this temporary change to the cap is not incorporated into the LCIM.

[27] In the CIM, this reallocation occurs for prospective analyses only. For retrospective analyses, the CIM assumes that the user enters actual GOMESA disbursements, which would reflect the 10 percent requirement.

4.3.2.1 CIM Estimation and Allocation of 8(g) Revenue

In the CIM, projections of 8(g) revenues are included in the data provided by the user for both backward-looking analyses and forward-looking analyses. The model allocates these 8(g) revenue estimates to the state level. To perform this allocation, the CIM uses a distribution derived from an approach similar to that described above for the distribution of GOMESA revenues. This distribution was developed based on the following steps:

1. ***Group 8(g) leases into categories by state:*** All 8(g) leases were grouped into nine categories:

   Five categories for leases within three miles of the state waters of a single state (TX-only, LA-only, AL-only, MS-only, FL-only).

   Four categories for leases within three miles of the state waters of neighboring states: (TX-LA, LA-MS, MS-AL, or AL-FL).[28]

2. ***Estimate future production for all leases.*** Following the process outlined for non-GOMESA leases in Section 4.3.1.1 above, reserves were allocated to individual 8(g) leases. Production on these leases was then projected based on the decline in reserves over time. Future production, by year, was then summed for all of the leases in each of the nine categories identified in Step 1.

3. ***Estimate distribution across states.*** Based on the production forecasts developed in Step 2 for each of the nine categories, the proportional distribution of 8(g) revenues across states was estimated.

For 8(g) leases within three miles of the border of more than one state, the CIM distributes 8(g) revenues equally between the two states, following section 8(g)(7) of the OCSLA.

The CIM applies the state-specific percentages from Step 3 to the estimate of 8(g) revenues entered by the user to generate estimates of 8(g) revenues by state.

4.3.2.2 LCIM Estimation and Allocation of 8(g) Revenue

The LCIM applies two approaches for estimating 8(g) revenues: one approach when users provide scenario information through the detailed leasing scenario spreadsheet and a second approach when users provide scenario data through the LCIM's streamlined leasing scenario interface. When users enter scenario data via the detailed leasing scenario spreadsheet, they provide estimates of 8(g) revenues by year. The LCIM uses these 8(g) revenue data as entered, making no adjustments to the values provided by the user.

When users instead rely on the streamlined leasing scenario interface, the LCIM uses data provided by the user in conjunction with assumptions and/or data included in the LCIM itself to estimate 8(g) revenues. For scenarios examining the impacts associated with an individual lease, the streamlined interface asks the user to indicate whether the lease is subject to 8(g). If the user provides an affirmative response, 8(g) revenues for the lease are assumed to be equal to 27 percent of all oil and gas sales revenues on the lease. If the user indicates that the lease is not subject to 8(g), the LCIM assumes no 8(g) revenues for the lease. For scenarios examining the impacts associated with multiple leases (i.e., for a lease sale or National OCS Program scenario), the LCIM estimates 8(g) revenues according to the following equation:

[28] Based on GIS analysis, there is only one lease within three miles of two states (Texas and Louisiana).

$$(19) \quad Rev8g_t = \sum_d \left(Rev_{d,t} \times e_d \times 27\%\right)$$

Where:

$Rev8g_t$ = 8(g) revenue for year t.

$Rev_{d,t}$ = oil and gas sales revenues associated with leases for water depth d and year t.

e_d = the percent of production in water depth d on leases subject to 8(g).

27% = the portion of revenues on leases subject to 8(g) that are distributed to the states according to the OCSLA 8(g) statutory requirements.

The LCIM includes default values for the percent of production in a given water depth that is on leases subject to 8(g) (e_d), though LCIM users may enter their own estimates for a given scenario. The default values, shown in Table 8, reflect production data for the year 2017.

Table 8. Default Portion of Oil and Gas Production on Leases Subject to 8(G), by Water Depth

Water Depth	Percent 8G
0–60m	20.8%
60–200m	4.1%
200–800m	0.0%
800–1600m	0.0%
1600+	0.0%

Sources:

BOEM. Data center: production data online query: https://www.data.boem.gov/Production/ProductionData/Default.aspx

BOEM. Data Center: lease information. Accessed at: https://www.data.boem.gov/Main/Leasing.aspx

The LCIM's spatial allocation of 8(g) revenues is dependent on the structure of the leasing scenario entered by the user. If the scenario is for a single lease and the user indicates that the lease is subject to 8(g), the LCIM asks the user to indicate the state to which 8(g) revenues will be distributed. This applies to any single lease scenario, regardless of whether the user enters data using the detailed leasing scenario spreadsheet or the streamlined leasing scenario interface. For a scenario examining a lease sale or National OCS Program (i.e., scenarios for more than one lease), the LCIM includes a default distribution of 8(g) revenues across states in the Gulf region based on the distribution for fiscal year 2017, as derived from ONRR disbursement data and shown in Table 9.[29]

[29] This method of allocating 8(g) revenues differs from that in BOEM's Cumulative Impacts Model, which allocates 8(g) revenues to states based on the spatial distribution of reserve depletion on existing 8(g) leases. Because the LCIM focuses exclusively on new leases, an allocation based on the expected reserve depletion of existing leases is unlikely to be representative. Although the spatial allocation of future 8(g) lease revenues is uncertain, relying on the allocation for the most recent year for which data are available is a transparent and straightforward method of allocation.

Table 9. Default Spatial Allocation of 8(g) Revenues for Multi-lease Scenarios

State	Percent
Alabama	9%
Louisiana	89%
Mississippi	1%
Texas	1%

Source: US Department of the Interior, Office of Natural Resources Revenue (ONRR). c2018. Disbursement by year. Washington (DC): US Department of the Interior; [accessed 2 November 2018]. https://revenuedata.doi.gov/downloads/disbursements/

4.3.3 Allocation of Historic Preservaton Fund (HPF) and Land and Water Conservation Fund (LCWF)

In addition to federal government revenues from GOMESA and 8(g), the CIM and LCIM also capture the economic and fiscal impacts of government expenditures related to the HPF and LWCF. The HPF and LWCF have funded an average of $63 and $122 million of grants and projects over the last seven fiscal years out of the total authorized funds of $150 and $900 million, respectively.[30]

4.3.3.1 CIM Allocation of HPF and LWCF Revenue

Within the CIM, the methods for allocating funds to the HPF and LWCF (excluding the GOMESA portion of the LWCF) differ for backward-looking compared to forward-looking analyses. For backward-looking analyses, the CIM uses disbursement data for the HPF and LWCF provided by the user in the E&D scenario spreadsheet. For forward-looking analyses, users may choose between two options for projecting the total funds flowing to the HPF and LWCF: (1) selecting an amount (up to the maximum of $150 and $900 million, respectively) or (2) using the annual average of the funds paid over the period from 2011 to 2017.[31] If the user chooses the first option, the CIM estimates total funds to the LWCF as the sum of two components: (1) the portion of GOMESA funds flowing to the LWCF, as estimated using the method outlined above in Section 4.3.1, and (2) the portion of non-GOMESA LWCF. The CIM allocates the LWCF and HPF funds spatially across GOM states and the rest of the US according to the percent of total funds awarded in each state over fiscal years 2011 through 2017. For the LWCF, which includes both state and federal projects, the CIM differentiates between state/local government expenditures and federal government expenditures using the average distribution between state and federal projects over the 2011–2017 period.[32]

[30] HPF and LWCF historical funding data for 2011–2016 were obtained from the Office of Natural Resources Revenue (USDOI ONRR c2018). 2017 data were provided to BOEM by the National Park Service via email on March 8, 2018 (LWCF data) and March 9, 2018 (HPF data).

[31] The CIM only includes the Non-GOMESA portion for LWCF funds, as broken out in the 2017 LWCF Certificate of Apportionment that the National Park Service provided to BOEM via email on March 8, 2018. The CIM assumes all LWCF disbursements prior to the beginning of GOMESA Phase II (FY2017) are non-GOMESA LWCF disbursements for the purposes of estimating the annual average non-GOMESA LWCF disbursement.

[32] LWCF funding data was used at the sub-fund level (e.g., Federal land acquisitions, State and local grants) to parse between state and federal spending (USDOI ONRR c2018).

4.3.3.2 LCIM Allocation of HPF and LWCF Revenue

To allocate funds to the HPF and LWCF (excluding the GOMESA portion of the LWCF) attributable to the lease(s) analyzed by the LCIM, the model assumes the amount disbursed to each fund is proportionate to the production on the lease(s) for a given year relative to total OCS production in the Gulf that same year. First, the LCIM estimates the proportion of total OCS production associated with the analyzed lease(s) by dividing total production from the scenario by total federal OCS GOM oil and natural gas production projected by EIA's Annual Energy Outlook.[33] The LCIM calculates a single ratio of production by converting natural gas production to BOE. Next, the LCIM scales the annual average disbursement to each fund (e.g., $63 million for the HPF, as discussed above) in proportion to the ratio estimated in the first step (i.e., the ratio of the production from the leasing scenario to total Gulf OCS production projected in the AEO).[34]

The LCIM allocates the LWCF and HPF funds spatially across Gulf states and the rest of the US according to the percent of total funds awarded in each state over fiscal years 2011 through 2017. For the LWCF, which includes both state and federal projects, the LCIM differentiates between state and/or local government expenditures and federal government expenditures using the average distribution between state and federal projects over the 2011–2017 period.

4.4 Application of IMPLAN Multipliers

After allocating OCS revenues according to the methods outlined above, the CIM and LCIM estimate the economic impacts associated with (1) federal government spending of revenues not allocated to other levels of government, (2) state governments spending monies distributed to them pursuant to GOMESA and 8(g) or through the LWCF and HPF, and (3) coastal political subdivisions spending monies distributed to them pursuant to GOMESA. To estimate the economic impacts associated with this spending, the CIM and LCIM use IMPLAN multipliers that reflect institutional spending patterns by various levels of government. These spending pattern data are available within IMPLAN. To assess the economic impacts of *federal* government spending, the CIM and LCIM rely on multipliers that reflect *federal* government spending patterns (i.e., spending across different sectors) for defense, non-defense, and investment and IMPLAN data on the distribution of federal spending across these three categories. For the economic impacts of *state government* and *coastal political subdivision* spending, the CIM and LCIM rely on IMPLAN multipliers that reflect state and local government spending patterns for education, non-education, and investment and IMPLAN data on the distribution of state and local government spending across these three categories. The IMPLAN spending pattern data used in the CIM and LCIM reflect differences in spending patterns between states/counties. That is, the pattern of state and local government spending is not the same across all states/counties.

The models' estimation of the economic impacts associated with spending by *state* governments differs for states within the Gulf of Mexico region (i.e., Texas, Louisiana, Mississippi, Alabama, and Florida) compared to states outside the region. To estimate the economic impacts of state spending outside the Gulf region, the CIM and LCIM apply an approach similar to that described above in Section 3.8.2.2 for industry expenditures in the rest-of-US region. Under this approach, the models first apply government spending multipliers for both the rest-of-US region and individual states, with the individual state multipliers reflecting state government spending patterns unique to each state. The CIM and LCIM then

[33] See EIA (2018a), Tables 60 and 61: Reference case projections for crude oil and natural gas production by supply region. The AEO projections are available through 2050. Production is extrapolated beyond 2050 using the compound annual growth rate between 2041 and 2050 separately for both oil and gas production.

[34] The total funds disbursed to the LWCF are calculated as the sum of the GOMESA funds allocated to the LWCF and the non-GOMESA LWCF funds estimated in this section.

calculate the residual between the total indirect and induced impacts for the rest-of-US and the sum of the state-level indirect and induced impacts. This residual is then allocated to states using the same gravity-based approach described in Section 3.8.2.2, using the OCS-related expenditures for individual states and the size of each state's economy as weights in the numerator of the gravity equation (see Equation 15 above). After performing the gravity calculations, the CIM and LCIM estimate the impacts for each state as the sum of (1) the impacts estimated based on the state-specific multipliers for individual states and (2) the state's portion of the residual described above, as estimated using the gravity-based approach.

For the Gulf region, the CIM and LCIM first allocate state government spending between the BOEM EIAs in each GOM state and the rest of the state. The models base this allocation on the spatial distribution of state government demand (within a given state) in IMPLAN. Table 10 shows this distribution for each state in the Gulf region. To estimate the economic impacts of state government spending in each EIA and rest-of-state area, the CIM and LCIM apply the same basic approach as described in Section 3.8.2.1 above. Under this approach, the CIM and LCIM first apply IMPLAN multipliers for all EIAs and rest-of-state areas combined to the government expenditures allocated to the Gulf in aggregate. The model also applies multipliers for individual EIAs and rest-of-state areas to the government expenditures allocated to each EIA and rest-of-state area. The model then distributes the direct, indirect, and induced impacts estimated for the all-Gulf analysis to individual EIAs and rest-of-state areas in proportion to the EIA- and rest-of-state-specific direct, indirect, and induced impacts estimated in the individual EIA and rest-of-state analyses.

Table 10. Distribution of State and Local Government Demand

Onshore Area	Percent of Total State and Local Government Demand
AL1	7.23%
AL2	0.51%
AL–Rest of State	92.26%
FL1	31.59%
FL2	1.12%
FL3	0.62%
FL4	3.54%
FL5	16.51%
FL6	2.86%
FL–Rest of State	43.75%
LA1	1.52%
LA2	21.18%
LA3	4.93%
LA4	2.11%
LA5	6.53%
LA6	30.68%
LA7	2.30%
LA–Rest of State	30.74%
MS1	44.87%
MS2	0.45%
MS–Rest of State	54.69%
TX1	4.90%

Onshore Area	Percent of Total State and Local Government Demand
TX2	5.76%
TX3	9.41%
TX4	0.05%
TX5	0.63%
TX6	0.02%
TX–Rest of State	79.23%

To estimate the economic impacts associated with spending by coastal political subdivisions (all of which are in the Gulf region), the CIM and LCIM aggregate this spending by EIA. For example, the spending by Harris County, Texas; Galveston County, Fort Bend County, Montgomery County, and Brazoria County is summed together, because these counties correspond to EIA TX3. In addition, consistent with the multipliers that the CIM and LCIM use to assess the economic impacts of industry expenditures, the models use multipliers for all five Gulf states collectively and distribute the direct, indirect, and induced economic impacts to individual EIAs and rest-of-state areas using the method described above for estimating the economic impacts of state government spending in the Gulf region (and described in further detail in Section 3.8.2.1).

To estimate the economic impacts associated with federal government spending, the CIM and LCIM follow an approach similar to that specified above for state government spending. As an initial step in this process, the models allocate federal expenditures to individual states based on IMPLAN data on federal defense, non-defense, and investment demand. To assess the economic impacts of federal expenditures in states outside the Gulf region, the CIM and LCIM apply multipliers that reflect federal government spending patterns for defense, non-defense, and investment in each respective state (and the rest-of-state area as a whole). Using these multipliers, the models follow the approach described above for state government expenditures (and described further in Section 3.8.2.2) to estimate impacts by state for the rest-of-US region. Similarly, for states within the Gulf region, the CIM and LCIM estimate the economic impacts of Federal spending based on the approach described above for state government spending (and described in greater detail in Section 3.8.2.1).

5 Impacts Related to Industry Profits

5.1 Introduction

The economic and fiscal impact estimates generated by the Cumulative Impacts Model (CIM) and Lifecycle Impacts Model (LCIM) reflect a variety of impacts associated with profits earned from Outer Continental Shelf (OCS) oil and gas activity. As shown in Figure 10, the estimation of profit-related economic and fiscal impacts begins with the calculation of industry profits, based on scenario data input by the model user. Though the CIM estimates profits for all oil and gas activity on the Gulf of Mexico (Gulf) OCS, the LCIM estimates profits associated with individual leases or groups of leases. Using their resulting profit estimates, the CIM and LCIM estimate government revenue collected from the taxation of corporate profits (at the federal and state level) and then distribute the residual after-tax profits between dividend payments to shareholders and retained earnings. Because dividends represent a form of personal income, the models also estimate government revenues associated with the taxation of dividends. To estimate federal taxes on both dividends and corporate profits, the CIM and LCIM account for changes in tax law codified in the Tax Cuts and Jobs Act of 2017 (GPO 2017), which reduced the corporate income tax rate and changed the rate structure and deductions for personal income taxes. Finally, the CIM and LCIM use IMPLAN multipliers to estimate the economic impacts associated with the expenditure of tax revenues (on corporate profits and dividends) and household expenditures of dividend payments.

Consistent with the other portions of the CIM and LCIM described in previous chapters, the models estimate the economic and fiscal impacts associated with OCS profits for Bureau of Ocean Energy Management (BOEM) economic impact areas (EIAs), the rest of state area for each state where these EIAs are located (i.e., states on the Gulf), and at the state level for areas outside the Gulf .

The sections that follow describe the main elements of the CIM's and LCIM's approach for estimating profit-related impacts, as illustrated in Figure 10.

5.2 Estimation of Profits

The CIM and LCIM differ in their approach for estimating profits. Because the CIM is designed to estimate impacts related to all OCS oil and gas activity, it must estimate profits for all OCS activity in the Gulf. In contrast, the LCIM focuses more narrowly on impacts related to a lease, lease sale, or National OCS Program. Thus, the estimation of profits in the CIM is more complicated because it must (a) account for amortized costs of past investments and (b) reflect a more diverse mix of activity than would typically be reflected in the LCIM. To account for this uncertainty, the CIM provides the user with more flexibility for estimating profits than the LCIM. As described in further detail below, the CIM allows the user to choose between (a) setting profits (as a percentage of revenues) to a pre-specified average derived from historical data, or (b) allowing the CIM to estimate profits endogenously based on projected revenues and costs. In contrast, the LCIM endogenously estimates profits for all scenarios.

In addition, unlike the CIM, the LCIM provides the user with estimates of the financial viability of a given lease or group of leases before performing the more detailed economic and fiscal impact calculations in the model. As described below, the LCIM's analyses of financial viability estimate the net present value of the cash flows on a lease or group of leases, as well as the payback period to recover costs incurred.

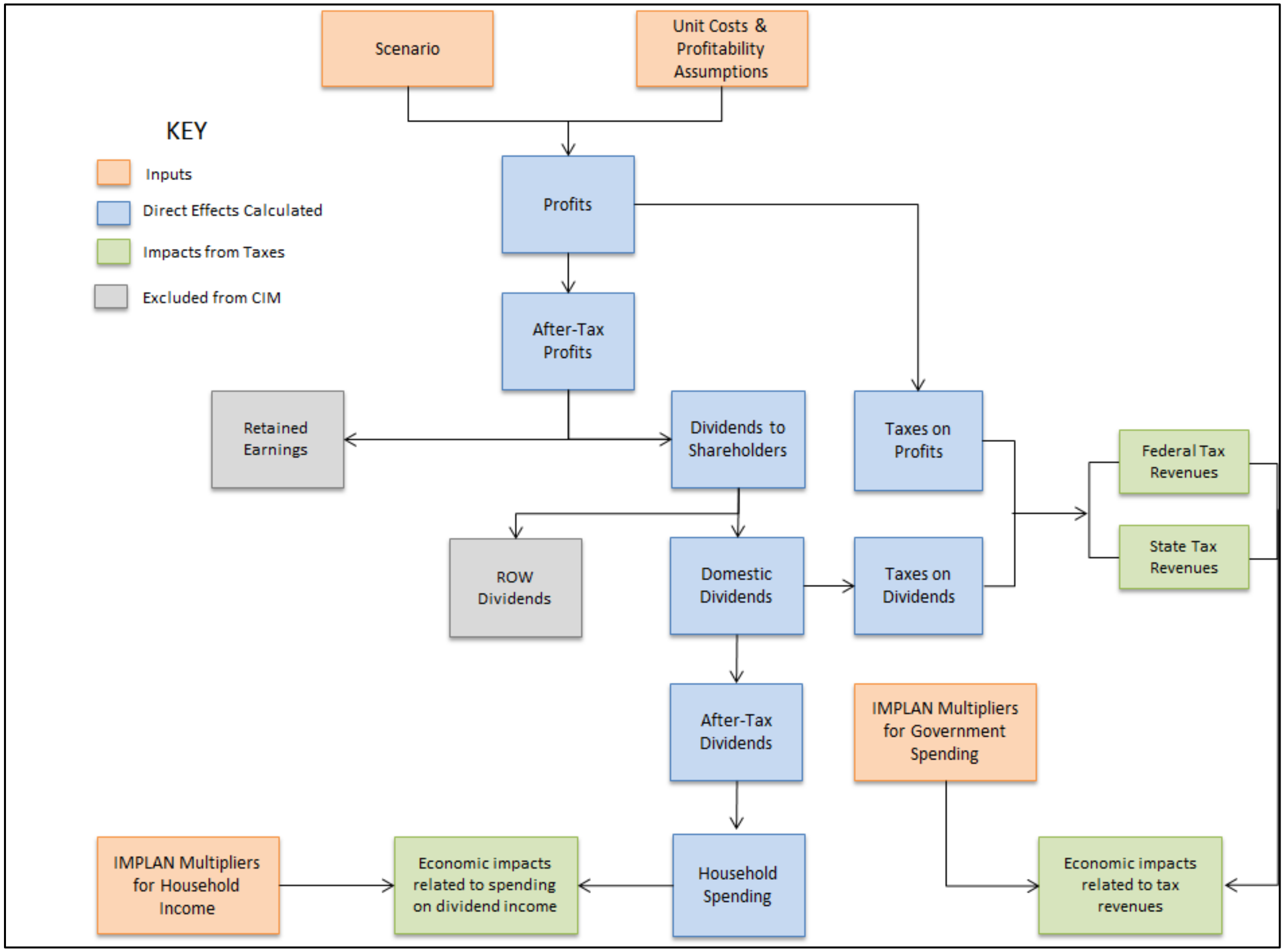

Figure 10. Schematic for estimation of profit-related impacts.

5.2.1 Conceptualization of Profits for Economic and Fiscal Impact Analysis

For economic impacts to be measured accurately under the CIM's and LCIM's input-output paradigm, the inputs need to represent an accurate measure of cash flows in a particular year, meaning the actual cash outflows from oil and gas (O&G) entities related to industry spending (capital and operations and management [O&M]), OCS revenue payments (royalties, bonus bids, and rents), and profits (taxes and dividends). As described in previous chapters, industry spending and OCS revenues are measured as an outflow of cash. In contrast, profits must first be measured as the difference between revenues and expenses, as this difference forms the basis for estimating taxes and dividends to be paid, and earnings to be retained. Put differently, the CIM and LCIM must reconcile their method for estimating cash expenditures with an approach to derive an appropriate measure of pre-tax profits, which can then be allocated to taxes, dividends, and retained earnings.

The O&G industry presents an analytic challenge in that it is characterized by long lag times between the expenditure of funds for exploration and development and the actual receipt of revenues from production and sales. In addition, a substantial proportion of exploration and development costs are "capitalized," meaning the outflow of cash is matched by a countervailing increase in the value of another asset, like plant and equipment. This cost is recovered over a period of time and using different methods through depreciation, depletion, and amortization (DD&A) expenses. These expenses, while representing a reduction to net income (or "profit") and while deductible for tax purposes, do not represent an outflow of cash (i.e., the cash was actually expended, and economic impacts ensued, when the capitalized purchase was made). Given that the approach for estimating operating and capital expenditures in Chapter 3 is structured to explicitly capture actual cash outflows, it is critical that the CIM and LCIM appropriately account for expense timing in their measure of profits.

The challenge is that expense timing is variable and difficult to model directly. In particular, the extent of these timing differences is affected by the amortization method employed, along with adjustments to reserve estimates and production levels. The data in Table 11 illustrate this difficulty, focusing on DD&A expense as a percentage of sales or revenues. The "RMA" (Risk Management Association) data are based on a sample of relatively small firms in NAICS code 211111 (crude petroleum and natural gas extraction), while the "EY" data show results for the 50 largest domestic O&G firms engaged in exploration and development activities.[35]

As shown in the table, DD&A expense as a percentage of sales can vary substantially across firms within a given year. In addition, the table illustrates how the percentages vary across years. The relationship of DD&A expense to sales holds relatively steady for the years 2011 through 2014. With the downturn in the sector beginning in 2015, however, the DD&A expense/sales ratio increases to 155 percent in the EY sample. Firms are obligated to accelerate expensing of capitalized costs if material changes occur to reserve volumes or their economic viability.

[35] More detailed explanations of the "RMA" and "EY" data sources are provided later in this chapter.

Table 11. Summary Depreciation, Depletion, and Amortization (DD&A) Statistics

Metric	Source	Year					
		2011	2012	2013	2014	2015	2016
DD&A expense as % of sales / revenue	RMA	13%	11%	11%	11%	14%	12%
	EY	28%	44%	36%	42%	155%	94%

Source: (RMA 2014); (RMA 2017); (EY 2017)

5.2.2 CIM Estimation of Profits

Given these considerations, the CIM allows the user to choose between (1) measuring pre-tax profits as a function of sales revenue and (2) estimating profits more directly based on estimated/projected revenues; estimated operating and capital expenditures; and estimated royalties, rental payments, and bonus bids. The first of these two options ensures that the profits measure is consistent with the CIM's measure of revenues and better smooths the distortions caused by variability in expense timing, while still fluctuating with changes in revenues and commodity prices. The second option, while more complex, ensures greater consistency between the model's estimates of profits and cash outflows, for operating and capital expenditures. Both of these options are discussed in further detail below.

Note that for the purposes of this document, "profits" represent pre-tax profits, after all relevant expenses have been subtracted from sales revenue. The CIM (and the LCIM) allocate this measure of pre-tax profits to three bins: taxes, dividends, and retained earnings. The allocation of pre-tax profits into these bins is described in subsequent sections.

5.2.2.1 CIM Option 1: Profits as a Percentage of Revenues

To assess the relationship between pre-tax profits and revenues, five different data series of financial performance for the O&G sector were reviewed, focusing on the ratio of pre-tax profits to revenues. These include the following:

- ***FRS-National.*** This series is based upon the Energy Information Administration's (EIA) Financial Reporting System (FRS) survey, form EIA-28 and related schedules (EIA 2011). The report focuses generally on the energy sector and covers all sectors from crude oil and natural gas production to refining and electricity generation. As such, the coverage is broader than offshore O&G exploration and development. In addition, the sample of 30 firms includes very large companies in the sector, averaging approximately $38.1 billion in annual sales. The series covers the years 1986 through 2009.
- ***FRS-Petroleum.*** This series is a breakout of the broader FRS-National dataset, but focuses on the petroleum sector (EIA 2011). The series, however, includes all upstream and downstream activities in the sector, from exploration and production, to refining and retail sales. Thus, the coverage is still broader than O&G exploration and production activities.
- ***EY.*** This series is based upon reports prepared by consultancy EY (EY 2012 and 2017). The EY studies include relevant financial and performance metrics based upon SEC 10K reports for the 50 largest domestic companies based on oil and gas reserve estimates, focusing on US exploration and production activities (both on-shore and off-shore). Average annual revenues for the sample equal approximately $2.1 billion, and the series covers the years 2007 through 2016.
- ***RMA.*** This series uses data from RMA's "Annual Statement Studies" (RMA 2004–2017). The RMA resource is an annual compendium of summary financial data and ratios compiled by member-banks and derived from representative samples of firms organized by NAICS code. In this case, the focus of analysis is on data for NAICS 211111, Crude Petroleum and Natural Gas Extraction. The sample size for each year varies, but for many years it is in excess of 100 firms.

The sample captures generally smaller firms in this NAICS code, with average annual revenues in the sample equaling $29.2 million. The series covers the years 2003 through 2016.

- ***IRS.*** This series uses US Internal Revenue Service (IRS) data from tax returns falling in NAICS 211110 (IRS 2013). Like the RMA dataset, it includes many smaller entities, with a sample size of almost 13,000 firms and average annual revenue of $13.3 million. The series covers the years 2000 through 2013.

Table 12 presents summary statistics for these data series. The table shows four measures of the average pre-tax profits as a percentage of revenues for each data series, based upon data availability and the O&G business cycle. The first average, "all years in series" shows the profit percentage for all years covered by the dataset. The second average presents this statistic for 2007 through 2009, the years where all of the series overlap. The table then presents data for 2007 through 2014 and 2007 through 2016 to focus on the most recent data.

The FRS series show low profit percentages relative to EY, RMA, and IRS, particularly in the overlapping 2007 through 2009 timeframe. This is likely because the FRS data capture the fully integrated suite of activities within the energy sector. In contrast, the EY data are more focused on O&G exploration and development activities. In addition, the EY series represents a sample of firms that are more aligned, in scope and scale, with firms engaging in offshore activities. Thus, the EY percentages are likely to be more relevant than the RMA or IRS results.

Note, however, that the EY results are heavily influenced by the substantial downturn in oil prices beginning in 2015. The period 2007 through 2016 captures two downturns and one upturn in the industry's business cycle. Considering these factors, the time period 2007 through 2014 (one full cycle peak to trough) is more relevant for estimating an appropriate profit percentage.

Thus, for Option 1 (profits specified as a percentage of revenues) the CIM uses 28 percent as the base case metric for calculating pre-tax profits as a percentage of revenues (or sales value). This figure is based on a representative sample of O&G firms engaged in exploration and development activities and their publicly-reported data. In addition, it captures a representative time period of the O&G business cycle. To account for variability in profits, however, the CIM also allows the user to adjust this figure based upon changing market conditions or other analytic factors. The model multiplies this profit percentage by the estimate of sales value for the user-specified scenario. The resulting measure, in dollars of pre-tax profits, is then allocated into estimates of taxes, dividends, and retained earnings as discussed in detail below.

Table 12. Pre-tax Profits as Percentage of Revenues

Data Series	Years in Series	Average percentage for:			
		All years in series	2007–2009	2007–2014 (IRS–2013)	2007–2016
FRS-National	1986–2009	8%	10%	NA	NA
FRS–Petroleum	1986–2009	10%	11%	NA	N-
EY	2007–2016	6%	28%	28%	6%
RMA	2003–2016	15%	21%	16%	14%
IRS	2000–2013	18%	18%	17%	NA

5.2.2.2 CIM Option 2: Direct Estimation of Profits

As an alternative to specifying profits as a fixed percentage of revenues, the CIM also gives the user the option of allowing the model to estimate profits endogenously based on projections of industry revenues (or historical estimates for retrospective analyses), operating costs, DD&A expenses, and royalties/rents/bonus bids. For a given year, the model estimates profits according to the following equation under this option:

$$(20)\quad \boldsymbol{\Pi_t = R_t - OPEX_t - DD\&A_t - RR_t}$$

Where

Π_t is profits in year t;

R_t is revenues in year t;

$OPEX_t$ is operating costs in year t;

$DD\&A_t$ is DD&A expense in year t, and

RR_t is royalties, rents, and bonus bids paid in year t.

Oil and Gas Price Forecasts in the CIM and LCIM

As noted in the discussion of the CIM's and LCIM's estimation of profits, the models rely on forecasts of oil and natural gas prices to project the revenues earned by the offshore oil and gas industry. The price forecast for oil represents the Gulf first purchase price and the models' forecast for natural gas represents the Henry Hub price. For both forecasts, the CIM relies on projections from the Energy Information Administration's Annual Energy Outlook 2018 (AEO 2018). Though the AEO publishes a forecast of the Henry Hub gas price, it does not include a forecast of the Gulf first purchase price for oil. In the absence of such a forecast, the CIM includes an approximation of the Gulf first purchase price derived from the AEO 2018 projection of the West Texas Intermediate (WTI) price and historical data for the 1998–2017 period indicating that the Gulf first purchase price is, on average, 94.9 percent of the WTI price.

For forward-looking analyses, the CIM derives values for each of these variables by integrating information from the user-entered cumulative exploration and development (E&D) scenario with other data residing in the model. The CIM estimates revenues for a given year (R_t) based on the oil and gas production forecasts in the cumulative E&D scenario and the oil and gas price forecasts included in the model.[36] Similarly, the model estimates annual operating costs based on the projections of various OCS

[36] The model also allows users to enter their own price forecast. If users enter their own forecast, they must ensure that all prices reflect the correct units ($/barrel for oil prices and $/Mcf for gas prices) and (within the model

oil and gas activities included in the E&D scenario (e.g., structures in operation) and the information referenced in Chapter 3 about the unit costs of these activities. For royalty, rental, and bonus payments, the CIM uses the values reported in the cumulative E&D spreadsheet without any changes.

Projecting the DD&A expense for a given year is a more complex undertaking. In the context of the CIM, projected DD&A reflect depreciation for anticipated investments in the E&D scenario as well as past investments not included in the E&D scenario but that are not yet fully depreciated. Thus, the CIM calculates DD&A as two separate expense streams:

$$(21)\quad \boldsymbol{DD\&A_t = DD\&A_{p,t} + DD\&A_{h,t}}$$

Where $DD\&A_{p,t}$ is DD&A in year t for projected investments included in the E&D scenario, and

$DD\&A_{h,t}$ is DD&A in year t for past (historical) investments that are not yet fully depreciated.

To project DD&A on projected investments included in the cumulative E&D scenario entered by the model user ($DD\&A_{p,t}$), the CIM (1) estimates the total capital costs associated with investments made in a given year using the unit cost information described in Chapter 3 and (2) depreciates these costs over time based on the historical trajectory of production for each water depth category. For example, as shown in Table 13, BOEM’s historical production and lease activity data suggest that, on average, 3.2 percent of the production on a lease at a water depth of 200 to 800 meters occurs during the fifth year following the drilling of exploration wells. Thus, for the purposes of estimating the DD&A associated with an exploration well drilled in a given year, the CIM assumes that 3.2 percent of the DD&A cost for that well is assigned to the fifth year following the drilling of the well. Though the temporal distribution of production (and therefore DD&A) on a given investment may vary from the historical distribution, the distribution across multiple investments is likely to be fairly consistent with the historical data.

The CIM does not project DD&A on bonus bids and platform removal expenditures. Though bonus bid payments are considered capital expenditures, the Tax Cuts and Jobs Act allows (through 2022) for a 100 percent deduction of bonus bids in the first year that the property was acquired and placed in service. As a result, the CIM treats bonus bid payments as operating costs.[37] Also, the CIM does not project DD&A on platform removal expenditures because platform removal occurs after production has ended. As a result, the CIM cannot rely on a depreciation schedule based on the trajectory of production as with other capital expenditures. Instead, the CIM treats platform removal expenditures as operating costs. While this is a simplification of how platform removal costs are likely to be treated by oil and gas companies, this assumption is likely to have a negligible impact on the CIM results.

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interface) specify the year’s dollars in which the price forecast is expressed. If the user would like to use a gas price forecast originally listed in \$/MMbtu, the prices must first be converted to \$/Mcf. The EIA recommends a conversion factor of 1 Mcf = 1.037 MMbtu based on the average heat content of US natural gas in 2017 (https://www.eia.gov/tools/faqs/faq.php?id=45&t=8).

[37] This is inconsistent with the LCIM, which spreads bonus bid costs over time. Such an allocation over time is more feasible in the LCIM because the oil and gas production projections in the LCIM scenarios correspond to the new leases on which the bonus bids in the scenario are paid. In contrast, the production data in the CIM scenarios reflect production on the new leases on which bonus bids in the scenario are paid, as well as production on older leases with no bonus bids included in the scenario.

Table 13. Distribution of Production by Water Depth

Years after First Exploratory Well	Water Depth				
	0–60m	60–200m	200–800m	800m–600M	1600M+
0	0.3%	0.0%	0.0%	0.0%	0.0%
1	1.9%	0.2%	0.2%	0.2%	0.2%
2	4.5%	0.8%	0.0%	0.0%	0.0%
3	7.0%	2.5%	0.6%	0.6%	0.6%
4	8.4%	4.3%	2.1%	2.1%	2.1%
5	10.0%	6.9%	3.2%	3.2%	3.2%
6	10.0%	8.4%	3.2%	3.2%	3.2%
7	8.7%	7.8%	3.6%	3.6%	3.6%
8	7.6%	8.5%	4.1%	4.1%	4.1%
9	5.8%	7.5%	6.0%	6.0%	6.0%
10	4.9%	6.2%	5.4%	5.4%	5.4%
11	3.9%	5.5%	6.0%	6.0%	6.0%
12	3.7%	4.6%	6.3%	6.3%	6.3%
13	3.0%	4.0%	6.1%	6.1%	6.1%
14	2.7%	3.9%	6.4%	6.4%	6.4%
15	2.3%	3.5%	5.7%	5.7%	5.7%
16	2.1%	3.0%	5.4%	5.4%	5.4%
17	1.8%	2.5%	6.0%	6.0%	6.0%
18	1.4%	2.3%	4.6%	4.6%	4.6%
19	1.3%	2.1%	3.1%	3.1%	3.1%
20	1.2%	2.3%	2.9%	2.9%	2.9%
21	1.0%	2.0%	2.8%	2.8%	2.8%
22	1.0%	1.8%	3.1%	3.1%	3.1%
23	1.0%	1.5%	2.2%	2.2%	2.2%
24	0.8%	1.5%	2.3%	2.3%	2.3%
25	0.7%	1.4%	2.1%	2.1%	2.1%
26	0.7%	1.4%	1.7%	1.7%	1.7%
27	0.6%	1.2%	1.5%	1.5%	1.5%
28	0.6%	0.9%	1.5%	1.5%	1.5%
29	0.5%	0.8%	1.1%	1.1%	1.1%
30	0.4%	0.6%	0.8%	0.8%	0.8%

Sources: Values derived from the following sources:

BOEM. "Borehole Online Query." Accessed at: https://www.data.boem.gov/Well/Borehole/Default.aspx

BOEM. "Production Data." Accessed at: https://www.data.boem.gov/Main/RawData.aspx

To project DD&A on past investments ($DD\&A_{h,t}$), a three-step process was applied that is similar in many ways to the approach described above for DD&A on future investments included in the user-defined cumulative E&D scenario. This process is as follows:

1. First, active leases with past investment activity were identified (e.g., well drilling) from BOEM's various lease datasets.[38, 39]

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[38] BOEM. "Borehole Online Query." Accessed at: https://www.data.boem.gov/Well/Borehole/Default.aspx

BOEM. "Platform Structure." Accessed at: https://www.data.boem.gov/Main/Platform.aspx

BOEM. "Pipeline Masters." Accessed at: https://www.data.boem.gov/Main/Pipeline.aspx

[39] The BOEM Data Center "Borehole" dataset tracks historical exploratory and development well drilling activity. However, the dataset does not track which exploratory wells are re-entered and completed and which development wells are non-producing (versus completed and producing). As a result, the CIM relies on assumptions about the average proportion of exploratory wells that are re-entered and completed and average proportion of development

2. For each of the leases identified in Step 1, the CIM estimates the capital expenditures associated with activity that has occurred on the lease, using the unit cost information described in Chapter 3.
3. The CIM depreciates these costs over time (to specific calendar years), based on the historical trajectory of production for each water depth category. For example, based on the data in Table 13, the CIM assigns 5.4 percent of the DD&A for an exploration well drilled in 200 to 800 meters of water in 2010 to the year 2020, as 2020 corresponds to year 10 in the table.

Following these steps for past investments on all active leases yields a projected time series of DD&A on past investments (i.e., $DD\&A_{h,t}$ by year). The CIM adds the projected value of $DD\&A_{h,t}$ for a given year to the estimate of DD&A for projected investments ($DD\&A_{p,t}$) for that same year to calculate total DD&A for the year.

One potential complication in applying this approach is that what is considered past investments changes over time. For example, if the CIM were run today (in 2019), investments projected in year 2 of the cumulative E&D scenario would be a projected investment. However, if the CIM is subsequently run again in 2021, the cumulative E&D scenario used at that time would not include activities that occurred in 2020. The model's estimates of DD&A associated with past investments would therefore need to be updated to reflect investment activity in 2020. More broadly, DD&A for past investments must be updated each year in the model to reflect activity from the previous year.

The CIM uses outputs from an automated spreadsheet for compiling historical OCS oil and gas activity data that forms the basis of the CIM's estimates of DD&A on past investments (i.e., $DD\&A_{h,t}$ by year). The activity data from this spreadsheet may be imported into the CIM, and the CIM automatically applies Steps 2 and 3 above to project DD&A on past investments.

5.2.3 LCIM Estimation of Profits

Similar to Option 2 for the CIM, the LCIM estimates profits directly based on projections of industry revenues, operating costs, DD&A expenses, and royalties/rents/bonus bids. For a given year, the model estimates profits according to the same equation as specified above for CIM Option 2 whereby profits are equal to revenues less operating expenditures; DD&A; and royalties, rents, and bonus bids.

As with CIM Option 2, the LCIM derives values for each of these variables based on user-entered data and other data residing in the model. The LCIM estimates revenues for a given year (R_t) based on the oil and gas price forecasts included in the model[40] and oil and gas production forecasts that are either input into or derived by the model. As described in Chapter 2, the production time series for a given scenario may be (1) input directly into the LCIM by model users through the detailed leasing scenario spreadsheet or (2) derived from a lump sum production estimate entered by the user for a lease or group of leases. Similarly, the model estimates annual operating costs based on the projections of various OCS oil and gas activities (again, either entered directly through the detailed leasing scenario spreadsheet or derived by the model based on more streamlined data entered by the user) and the information referenced in Chapter 3 regarding the unit costs of these activities.

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wells that are producing compared to non-producing. Specifically, the CIM assumes that 33 to 38 percent of exploratory wells are re-entered and completed and 25 to 45 percent of development wells are non-producing (varying based on water depth). These percentages match the ratios for 2018 in the 2017 to 2022 Gulf Cumulative Case E&D Scenario associated with BOEM's 2017–2022 National OCS Leasing Program. These assumptions may be modified by the user as described in the CIM User Guide.

[40] Similar to the CIM, the LCIM also allows users to enter their own price forecast by scenario. If users enter their own forecast, they must ensure that all prices reflect the correct units ($/barrel for oil prices and $/Mcf for gas prices) and (within the model interface) specify the year's dollars in which the price forecast is expressed.

To project DD&A on projected investments reflected in the leasing scenario entered by the model user ($DD\&A_t$), the LCIM (1) estimates the total capital costs associated with investments made in a given year using the unit cost information described in Chapter 3 and (2) depreciates these costs over time. More specifically, the costs of an investment are assigned to the year of the investment and subsequent years in proportion to each year's total oil and gas production (expressed as BOE) relative to cumulative BOE production for the year of the investment and all later years. For scenarios input into the LCIM through the detailed scenario spreadsheet, the LCIM estimates the distribution of oil and gas production (in BOE) over time based on the production schedule provided by the user. For scenarios input into the model with the streamlined leasing scenario interface, the model relies on the historical distributions for production presented in Appendix A. For example, as shown in Table 14, BOEM's historical production and lease activity data suggest that, on average, 5.2 percent of the production on a lease at a water depth of 200 to 800 meters occurs seven years following the initiation of production. Exactly which year this represents following the initiation of the lease depends on the assumed start year of production. As described in Appendix A, based on the 10th and 90th percentiles of BOEM's historical lease data, this may vary from year 2 to year 10 of the lease term, while the 50th percentile value would start production approximately five years following lease issuance.[41] Therefore, if the user were to choose the 50th percentile assumption for a lease beginning in 2020, the LCIM would allocate 5.2 percent of capital expenditures (e.g., for drilling) to 2032 for the purposes of estimating DD&A (i.e., five years of no production plus an additional seven years of production).

The LCIM applies two approaches for allocating royalties, rents, and bonus bids across time for the purposes of estimating profit: one approach for royalties and a second approach for rents and bonus bids. For royalties, the LCIM counts payments made to the government as an expense against profits for the year that such payments are made, effectively treating royalties like an O&M expense for the purposes of estimating profit. For example, if producers pay $2 million in royalties in 2030 on a given lease or group of leases, the LCIM counts the full $2 million against profits in 2030. For rents and bonus bids, the model applies an approach similar to that described above for capital expenses. Although rents and bonus bid payments tend to be front-loaded during the life of a lease (i.e., until production begins for rents and at lease issuance for bonus bids), these costs support the lessee's ability to produce oil and/or gas on the lease at a later date. In effect, these payments are investments in the right to produce. Therefore, for the purpose of estimating profits, the LCIM distributes rent and bonus bid payments to the years over which production occurs (in BOE terms), in proportion to annual production.

Table 14. Distribution of Production by Water Depth

Years after Production Begins	Water Depth				
	0–60m	60–200m	200–800m	800m–1600M	1600M+
0	9.0%	7.4%	1.5%	1.5%	1.5%
1	16.6%	13.2%	5.1%	5.1%	5.1%
2	12.2%	10.5%	5.7%	5.7%	5.7%
3	9.0%	8.9%	7.4%	7.4%	7.4%
4	6.8%	7.1%	8.1%	8.1%	8.1%
5	5.5%	6.0%	7.3%	7.3%	7.3%
6	4.6%	5.1%	6.0%	6.0%	6.0%
7	3.7%	4.2%	5.2%	5.2%	5.2%
8	3.2%	4.0%	4.2%	4.2%	4.2%
9	2.9%	3.4%	3.3%	3.3%	3.3%
10	2.6%	3.0%	3.2%	3.2%	3.2%
11	2.4%	2.6%	3.0%	3.0%	3.0%

[41] As described in Chapter 2, the user has the option of choosing the mean value or the 10th, 25th, 50th, 75th, or 90th percentile.

Years after Production Begins	Water Depth				
	0–60m	60–200m	200–800m	800m–1600M	1600M+
12	2.1%	2.4%	3.4%	3.4%	3.4%
13	1.9%	2.2%	4.9%	4.9%	4.9%
14	1.7%	2.0%	3.7%	3.7%	3.7%
15	1.7%	2.0%	2.6%	2.6%	2.6%
16	1.6%	1.9%	3.0%	3.0%	3.0%
17	1.4%	1.8%	5.3%	5.3%	5.3%
18	1.2%	1.8%	3.2%	3.2%	3.2%
19	1.2%	1.5%	2.7%	2.7%	2.7%
20	1.2%	1.4%	2.6%	2.6%	2.6%
21	1.1%	1.3%	3.2%	3.2%	3.2%
22	1.0%	1.1%	1.3%	1.3%	1.3%
23	0.9%	1.0%	1.1%	1.1%	1.1%
24	0.9%	0.8%	0.7%	0.7%	0.7%
25	0.8%	0.7%	0.6%	0.6%	0.6%
26	0.7%	0.7%	0.5%	0.5%	0.5%
27	0.6%	0.6%	0.4%	0.4%	0.4%
28	0.5%	0.5%	0.3%	0.3%	0.3%
29	0.5%	0.4%	0.3%	0.3%	0.3%
30	0.4%	0.4%	0.2%	0.2%	0.2%

Sources: Values derived from the following source:

BOEM. "Production Data." Accessed at: https://www.data.boem.gov/Main/RawData.aspx

5.2.3.1 LCIM Estimation of Profits for Lease Viability Test

Distinct from the estimation of profits for the LCIM's analyses of economic and fiscal impacts, the model performs a separate analysis of lease viability that estimates two measures of profitability: (1) net present value (NPV) of income and (2) the payback period. Combined, these metrics allow the model user to evaluate whether the modeled investments for a lease (or group of leases) appear financially viable and add value to the lease holder(s). Projected investments that should be accepted by the associated firms have a positive NPV, and the investments' payback period, at a minimum, should be shorter than the duration of the leases (or through the productive period of the leases). Investments with shorter payback periods are generally preferable relative to those with longer payback periods. If a leasing scenario shows a negative NPV or a payback period longer than the productive term of the lease, the LCIM provides the user with an opportunity to alter the parameters of the leasing scenario. Users may make any changes that they deem appropriate or proceed with the estimation of economic and fiscal impacts.

The LCIM's approach for estimating NPV and the payback period is as follows:

- ***NPV***: NPV represents the present value of the net cash flows associated with a lease or group of leases. It reflects revenue from the sale of any oil and gas produced on the lease and all capital costs and O&M costs incurred by the lease holder(s), including payments made to the government for royalties, bonuses, and rents. A key difference between NPV and the estimation of profits as described in Section 5.2.1 is that investment expenses are not spread over time when calculating NPV. Instead, the model estimates the present value of these expenses based on the year in which cash is expended. For example, if a lease holder incurs $200 million in well drilling costs in year 5 of a lease, the LCIM estimates the present value of this $200 million investment by discounting it back over five years. The model does not spread the $200 million over the production schedule for the lease before estimating the present value of the expenditure. To estimate NPV, the LCIM uses the oil and gas industry discount rate entered by the user.
- ***Payback period:*** The payback period represents the length of time for a lease (or group of leases) to recover the costs incurred by the lease holder(s). Unlike the NPV, the payback period ignores

the time value of money. There is no single formula for the payback period. Instead, the LCIM sums total cash outflows and tracks revenues year by year until (and if) cumulative revenues are greater than or equal to expenditures (both measured in nominal terms).

5.3 Estimation of Corporate Income Taxes

After estimating profits, the CIM and LCIM estimate corporate income taxes on those profits, both at the federal and state level.

5.3.1 Effective Federal Corporate Income Tax Rate

In recognition that offshore oil and gas production companies vary widely in size, structure and profitability, CIM and LCIM users may enter their own assumption regarding the effective federal corporate income tax rate or choose one of two rates included in the model as options. The pre-loaded effective federal corporate income tax rates that reside in the model were estimated using two datasets:

1. ***IRS data:*** To reflect the tax experience of all of the firms that work in offshore oil and gas, IRS data were used to generate one of the effective federal corporate income tax rates in the CIM and LCIM.
2. ***EY data:*** To simulate the tax experience of large operators, an alternative effective federal corporate income tax rate was estimated based on EY's oil and gas reserves studies, which include financial results for the largest oil and gas companies active in the United States.

To estimate the effective corporate income tax rate at the federal level using IRS data, historical data on the oil and gas sector's tax receipts and revenues were collected and analyzed for the years 2000–2013 (IRS c2017a). The weighted average historical effective tax rate was then calculated as total income tax over net income, with total receipts as the weighting factor. This method generated an effective tax rate of 11.4 percent. To account for the 2017 Tax Cuts and Jobs Act, which lowered the top marginal federal corporate income tax rate from 35 percent to 21 percent, the historical effective tax rate was adjusted using Congressional Budget Office (CBO) projections of corporate tax revenue for 2018–2027 made prior to the passage of the tax bill, and the CBO cost estimate of the tax bill.[42] The CBO projected that the tax bill will reduce corporate tax revenue by 16.5 percent. The historical effective tax rate was therefore reduced by this amount, which resulted in an adjusted effective federal corporate income tax of 9.6 percent.

To capture the tax experience of the largest oil and gas firms, data on the pre-tax results of operations and income tax payments for 2007-2016 were compiled from EY's 2012 and 2017 oil and gas reserves studies (EY 2012 and 2017).[43] EY reported the financial results of the largest 50–75 oil and gas companies by total estimated reserves that are active in the US. The effective tax rate (for all taxes) was calculated over the 2007–2016 period as total income taxes over pre-tax results of operations, weighted by annual revenues. Federal income taxes were isolated from total income taxes based on the following five-step process:

[42] For CBO's pre-tax bill tax revenue projections for 2017–2027, see Congressional Budget Office (2017a). For CBO's adjustment to 2017–2027 tax revenue resulting from provisions of the tax bill, see Congressional Budget Office (2017b).

[43] Note that the 2012 study compiled data for the 75 largest companies active in the US for 2007–2011, while the 2017 study included data for the 50 largest companies for 2012–2016.

1. First, a composite average of the state-level effective corporate income tax rate was calculated,[44] using oil and gas operating surplus by state[45] as weights.
2. The composite state effective corporate income tax rate was then applied to the annual EY data on pre-tax results of operations (revenues less production costs; exploration expense; DD&A; and other expenses). The resulting value represents income tax paid to state governments.
3. The value estimated in Step 2 was then subtracted from EY's income tax payments data, yielding an estimate of taxes paid to the federal government.
4. The federal tax payments estimated in Step 3 were divided by pre-tax results of operations to derive a weighted average federal effective corporate income tax rate for 2007–2016 of 33.4 percent.
5. Like the federal effective tax rate estimated using the IRS data, this rate was adjusted for the projected effects of the 2017 Tax Cuts and Jobs Act. However, unlike the method used for the IRS-based effective tax rate, the EY-based rate was scaled using the change in the top marginal federal corporate income tax rate; the 2017 Tax Cuts and Jobs Act lowered the top marginal rate from 35 percent to 21 percent, a 40 percent reduction. The effective tax rate for 2007–2016, as estimated in Step 4, was therefore reduced by 40 percent, which results in a 20 percent federal effective corporate income tax rate. If the effective rate of 33.4 percent estimated in Step 4 were instead reduced by the 16.5 percent figure obtained from the CBO study, the resulting rate would be greater than the marginal corporate income tax rate established by the 2017 Tax Cuts and Jobs Act.

In summary, the two effective federal corporate income tax rates included in the CIM and LCIM are 9.6 percent (derived from IRS data) and 20 percent (derived from EY data).

5.3.2 State-Level Corporate Income Tax Rates

The CIM and the LCIM apply state-level effective corporate income tax rates derived from data obtained from multiple sources. The basic formula for estimating these tax rates is as follows:

$$(22) \quad ET_{State} = \frac{TC_{State}}{CP_{State}}$$

Where:

ET_{State} = Effective tax rate in a given state;

TC_{State} = Corporate revenue taxes collected in a given state, and

CP_{State} = Estimated corporate profits generated in a given state.

The state level estimates of corporate taxes collected (TC_{state}) are based on corporate income tax data from the US Census, supplemented by additional data published by the states on various specialized taxes. The US Census publishes state revenue from taxes by tax category in its *Annual Survey of State Government Tax Collections*. Corporate income tax is among the categories the Census uses to organize the data. While the Census data reflect taxes on corporate profits, they omit "specialized" corporate income taxes on particular industries and other relevant corporate taxes. For example, some states that do not levy a corporate income tax on all corporations in the state, such as South Dakota and Ohio, collect a corporate income tax from financial institutions. Additionally, while the top marginal rate is the rate each state imposes on the net income of corporations according to state statutes, it omits other categories of state

[44] For a discussion of the LCIM's state corporate income tax rate estimates, see Section 5.3.2.

[45] US Bureau of Economic Analysis (2019).

taxes that are collected on the basis of corporate revenue. To develop comprehensive estimates of state corporate taxes, the Census Bureau's state-level corporate income tax data for 2016 were integrated with data from state department of taxation websites on state tax proceeds for year 2016 corporate tax revenues not reported in the Census data. Table 15 summarizes the proceeds states realized from taxes on corporate revenue and the tax sources of those proceeds, according to these state data and the U.S. Census data. The estimates in the table served as BOEM's estimates of TC_{state} for the purposes of estimating a state's corporate income tax rate (as represented by Equation 22).

State level data on before-tax corporate profits (CP_{State} in Equation 22), *per se*, are not readily available from publicly available sources. Data are available, however, on corporate profits at the national level and gross operating surplus at the state level. The US Federal Reserve Bank of St. Louis has collected total before-tax corporate profits from current production (with inventory valuation adjustment and capital consumption adjustment) for the entire US from 1947–2016 through the Federal Reserve Economic Data program ("FRED").[46] The data originate with the Bureau of Economic Analysis' (BEA's) National Income and Product Accounts ("NIPAs") of the United States. The data define corporate profits as the net income corporations experience before the payment of income taxes, less capital gains and dividends, and add back bad debt, depletion, and capital loss expenses. BEA (2017) also converts tax return items that businesses report on a historical-cost basis–inventory withdrawals and depreciation of fixed assets – to current-cost basis. Thus, the inventory valuation adjustment and capital consumption adjustment assess the current value of goods and services, in line with BEA's GDP calculation.

[46] See FRED Federal Reserve Bank of St. Louis (n.d.).

Table 15. 2016 State Proceeds from Corporate Revenue Taxes

State	Total State Revenue from Corporate Revenue and Income Taxes	Tax	Specific Tax Revenue1
Alabama	$376,680,000	Corporate Income Tax	$376,680,000
Alaska	$212,252,000	Corporate Income Tax	$212,252,000
Arizona	$570,548,000	Corporate Income Tax	$570,548,000
Arkansas	$450,159,000	Corporate Income Tax	$450,159,000
California	$9,902,185,000	Corporate Income Tax	$9,902,185,000
Colorado	$626,109,000	Corporate Income Tax	$626,109,000
Connecticut	$719,467,000	Corporate Income Tax	$719,467,000
Delaware	$318,152,000	Corporate Income Tax	$318,152,000
Florida	$2,272,230,000	Corporate Income Tax	$2,272,230,000
Georgia	$981,002,000	Corporate Income Tax	$981,002,000
Hawaii	$108,169,000	Corporate Income Tax	$108,169,000
Idaho	$188,996,000	Corporate Income Tax	$188,996,000
Illinois	$3,367,461,000	Corporate Income Tax	$3,367,461,000
Indiana	$1,034,367,000	Corporate Income Tax	$1,034,367,000
Iowa	$376,865,000	Corporate Income Tax	$376,865,000
Kansas	$391,877,000	Corporate Income Tax	$391,877,000
Kentucky	$606,840,000	Corporate Income Tax	$606,840,000
Louisiana	$171,579,000	Corporate Income Tax	$171,579,000
Maine	$137,492,000	Corporate Income Tax	$137,492,000
Maryland	$1,129,008,000	Corporate Income Tax	$1,129,008,000
Massachusetts	$2,333,892,000	Corporate Income Tax	$2,333,892,000
Michigan	$898,213,000	Corporate Income Tax	$898,213,000
Minnesota	$1,515,697,000	Corporate Income Tax	$1,515,697,000
Mississippi	$463,111,000	Corporate Income Tax	$463,111,000
Missouri	$328,736,000	Corporate Income Tax	$328,736,000
Montana	$118,969,000	Corporate Income Tax	$118,969,000
Nebraska	$307,672,000	Corporate Income Tax	$307,672,000
Nevada	$143,507,593	Commerce Tax[2]	$143,507,593
New Hampshire	$700,237,000	Corporate Income Tax + Business Enterprise Tax[3]	$700,237,000
New Jersey	$2,229,487,000	Corporate Income Tax	$2,229,487,000
New Mexico	$113,942,000	Corporate Income Tax	$113,942,000
New York	$4,181,811,000	Corporate Income Tax	$4,181,811,000
North Carolina	$1,066,511,000	Corporate Income Tax	$1,066,511,000
North Dakota	$103,069,000	Corporate Income Tax	$103,069,000
Ohio	$1,674,685,104	Commercial Activity Tax	$1,641,450,104
		Financial Institution Tax[4]	$33,235,000
Oklahoma	$327,783,000	Corporate Income Tax	$327,783,000
Oregon	$609,868,000	Corporate Income Tax	$609,868,000
Pennsylvania	$3,761,138,000	Corporate Income Tax	$2,456,231,000
		Gross Receipts Tax[5]	$1,304,907,000
Rhode Island	$144,269,000	Corporate Income Tax	$144,269,000
South Carolina	$440,489,000	Corporate Income Tax	$440,489,000
South Dakota	$32,684,000	Bank Franchise Tax	$32,684,000
Tennessee	$1,538,649,000	Corporate Income Tax	$1,538,649,000
Texas	$3,881,176,449	Franchise Tax[6]	$3,881,176,449
Utah	$333,358,000	Corporate Income Tax	$333,358,000
Vermont	$98,336,000	Corporate Income Tax	$98,336,000
Virginia	$752,689,000	Corporate Income Tax	$752,689,000
Washington	$3,633,250,000	Business & Occupation Tax[7]	$3,633,250,000
West Virginia	$144,680,000	Corporate Income Tax	$144,680,000
Wisconsin	$986,785,000	Corporate Income Tax	$986,785,000

State	Total State Revenue from Corporate Revenue and Income Taxes	Tax	Specific Tax Revenue1
Wyoming	$0	Corporate Income Tax	$0
District of Columbia	$556,468,000	Corporate Income Tax	$556,468,000

Notes:

[1] Except as otherwise noted, state revenue from corporate income taxes from US Census Bureau (2017).
[2] Nevada Department of Taxation (2017).
[3] Census data on New Hampshire corporate income tax revenue includes revenue from both New Hampshire's corporate income tax and its business enterprise tax. The Census does not parse revenue from the corporate income tax and revenue from the business enterprise tax, so the two taxes are presented on a single line.
[4] Ohio Commercial Activity Tax (Ohio . . . 2013).
[5] Pennsylvania gross receipt tax (Pennsylvania . . . c2020).
[6] Franchise tax overview and franchise tax (Comptroller.Texas.gov . . .c2020; c2019).
[7] Washington Business & Occupation Tax: Washington State Department of Revenue (undated).

BEA reports data on gross operating surplus nationally and for each state and the District of Columbia. For each three-digit NAICS code, BEA calculates gross operating surplus as net income plus proprietors' income, rental income of persons, net interest, capital consumption allowances, business transfer payment, nontax payments, the current surplus/deficits of government enterprises, and fixed investment (BEA 2017). BEA generates gross operating surplus data by state, in part, by distributing national corporate profit to each state using industry-dependent methodologies. For example, BEA distributes insurance carriers' national corporate profits to the states based on each state's share of total net premiums earned by firms that use insurance industry NAICS codes (net premiums equal total premiums minus losses) (BEA 2017).

To calculate corporate profits by state (CP_{State}), BEA's 2015 gross operating surplus data for private industries (non-governmental entities) was collected at the national level and at the state level (BEA 2019). These data were then used to calculate state factors to determine the proportion of the national gross operating surplus that was generated in each state. This is expressed as:

(23) $$SF_{State} = \frac{GOS_{State}}{GOS_{U.S.}}$$

Where:

SF_{State} = State Factor for a given state;

GOS_{State} = BEA's 2015 Private Industry Gross Operating Surplus for a given state; and

$GOS_{U.S.}$ = BEA's 2015 Private Industry Gross Operating Surplus for the United States as a whole.

Each state factor was then multiplied by BEA's total national before-tax corporate profit figure for 2016, as obtained through FRED. This effectively scaled the before-tax corporate profits for the United States to each state and the District of Columbia, using each state's proportion of gross operating surplus as the scaling mechanism.

(24) $$CP_{State} = CP_{U.S.} \times SF_{State}$$

Where:

CP_{State} = Estimated Corporate Profits generated in a given state;

$CP_{U.S.}$ = BEA's 2016 Corporate Profits for the United States as a whole; and

SF_{State} = State Factor for a given state (calculated above using BEA's gross operating surplus as the scaling mechanism).

Finally, substituting the estimated corporate profits by state (as estimated by Equation 24) into Equation 22 along with total taxes collected on corporate revenue in a given state in 2016 (as summarized in Table 15) yields the effective corporate income tax rate by state.[47] Table 16 summarizes these estimates.

To apply the effective corporate income tax rates shown in Table 16, the CIM and LCIM must allocate corporate profits to individual states. Ideally, the models would use existing data on the distribution of industry profits by state as the basis for this allocation, but no such data exist in the public domain. Developing such a distribution is complicated by the fact that the states in which firms engaged in offshore oil and gas activity may be different than the states in which they normally operate. In the absence of detailed data on the spatial distribution of industry profits, the CIM and LCIM allocate profits to states in proportion to output for IMPLAN Sector 20: Extraction of natural gas and crude petroleum, as obtained from IMPLAN.

Table 16. Effective State Corporate Income Tax Rates

State	Rate	State	Rate
Alabama	0.4%	Montana	0.5%
Alaska	0.9%	Nebraska	0.5%
Arizona	0.4%	Nevada	0.2%
Arkansas	0.8%	New Hampshire	2.2%
California	0.8%	New Jersey	0.9%
Colorado	0.4%	New Mexico	0.3%
Connecticut	0.6%	New York	0.6%
Delaware	0.8%	North Carolina	0.4%
District of Columbia	1.6%	North Dakota	0.4%
Florida	0.6%	Ohio	0.6%
Georgia	0.4%	Oklahoma	0.3%
Hawaii	0.3%	Oregon	0.5%
Idaho	0.6%	Pennsylvania	1.1%
Illinois	0.9%	Rhode Island	0.6%
Indiana	0.6%	South Carolina	0.5%
Iowa	0.4%	South Dakota	0.1%
Kansas	0.5%	Tennessee	1.0%
Kentucky	0.7%	Texas	0.5%
Louisiana	0.1%	Utah	0.5%
Maine	0.6%	Vermont	0.8%
Maryland	0.7%	Virginia	0.4%
Massachusetts	1.1%	Washington	1.7%
Michigan	0.4%	West Virginia	0.4%
Minnesota	1.0%	Wisconsin	0.7%
Mississippi	1.0%	Wyoming	0.0%
Missouri	0.2%		

5.4 Estimation of Dividend Taxes

After the IRS and individual states levy taxes on corporate income from offshore oil and gas production, firms engaged in offshore oil and gas activity retain these earnings, distribute them to shareholders as dividends, or some combination of both options. The federal government and the states collect taxes on dividends paid to US residents. To estimate these tax collections, the CIM and LCIM calculate domestic dividend payments and apply dividend tax rates derived from data obtained from the IRS and the Tax Foundation, as detailed below.

[47] The resulting effective tax rate does not include local government revenue from corporate income taxes.

5.4.1 Estimation of Domestic Dividend Payments

Based on BEA data on dividend payments and corporate profits for the oil and gas extraction industry over the 2000–2014 period, an estimated 28 percent of after-tax profits are paid out as dividends by the industry and that the remaining 72 percent remains as retained earnings. [48]

Of the dividends paid to shareholders, the CIM and LCIM estimate economic and fiscal impacts only for those dividends paid to shareholders residing in the US. Absent industry-specific data on the distribution between domestic and international dividend payments, the CIM and LCIM uses the national average proportion of net corporate domestic dividend payments out of net corporate dividends.[49] This yields an estimate that 83 percent of dividends are paid to domestic shareholders.

5.4.2 Estimation of Taxes on Dividends

Following the estimation of dividend payments to US households, the CIM and LCIM estimate federal and state taxes on these dividends. At the federal level, dividends are subject to the following taxes:

- *Qualified dividends* are subject to capital gains brackets and rates; and
- *Nonqualified dividends* are dividends from stock held for a short period of time, dividends on preferred stock, and dividends received during short sales and similar transactions (IRS 2018a). They are subject to personal income brackets and rates.
- Both qualified and nonqualified dividends are also subject to the Net Investment Income Tax (NIIT). If an individual's adjusted gross income exceeds certain thresholds depending on filing status, the NIIT taxes the lesser of the amount by which adjusted gross income exceeds the threshold or total net investment income, which comprises taxable interest, all dividends, annuities, and royalties and business interests, at a rate of 3.8 percent (IRS 2018b).

To estimate the overall federal tax rate on dividends, the total taxes that US tax filers pay on dividends – the sum of the above three bullets–was divided by total dividends US tax filers receive. IRS data for the most recent year for which data were available, tax year 2015, were used to generate this estimate.

The 2017 Tax Cuts and Jobs Act changed the capital gains tax brackets that are used to tax qualified dividends and the personal income tax rates and tax brackets that are used to tax nonqualified dividends; the law did not alter the NIIT tax rate or income thresholds for individuals. Because tax return data reflecting the 2017 Act were not yet available at the time of the CIM's and LCIM's development, the tax rate paid on dividends (based on the brackets and marginal rates in the new law) was applied to data from year 2015 tax returns.

The specific steps for these calculations are as follows:

- The most recent available data on adjusted gross income, qualified and nonqualified dividends, and filing status (i.e., married joint return, married separate returns, head of household, and singe) were collected from the IRS for tax year 2015.[50]

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[48] Calculated as the weighted average from the BEA (2000-2014) National Income and Product Accounts for the period 2000–2014, based on Table 6.20D (Net Corporate Dividend Payments by Industry) and Table 6.19D (Corporate Profits After Tax by Industry).

[49] Calculated as weighted average from 2000–2016. US BEA. Table 6.20D. Net Corporate Dividend Payments by Industry.

[50] US Internal Revenue Service, Table 2. Individual Income and Tax Data, by State and Size of Adjusted Gross Income, Tax Year 2015, accessed at: https://www.irs.gov/statistics/soi-tax-stats-historic-table-2; and US Internal Revenue Service, Table 1.2. All Returns: Adjusted Gross Income, Exemptions, Deductions, and Tax Items, by Size

- IRS data for adjusted gross income sorted by filing status were available, but not for dividends sorted by filing status. Qualified and nonqualified dividends were therefore distributed to each filing status category proportional to that category's adjusted gross income.
- The IRS data were not available by the tax brackets established in the 2017 Tax Cuts and Jobs Act, but by income segments that did not match either personal income or capital gains tax brackets. Qualified and nonqualified dividends were therefore distributed to the capital gains and personal income tax brackets under the 2017 Act for each filing status from the income segments provided by the IRS, assuming a uniform distribution of income within each category.
- The US has a progressive personal income tax system. For example, for a single filer, the first $9,525 of income is taxed at 10 percent, the next $29,175 of income up to $38,700 in total income is taxed at 12 percent, etc. Nonqualified dividends were assumed to constitute the last income that individuals reported. Therefore, only the highest personal income tax rate was applied on nonqualified dividends for those dividends in each tax bracket. Capital gain tax rates are not progressive, so this consideration does not apply to qualified dividends.

Table 17 summarizes the IRS dividend data from tax year 2015, sorted by the 2017 Act's personal income tax bracket and by filing status. The table presents total qualified and nonqualified dividends by tax bracket and filing status, tax rates for qualified dividends, nonqualified dividends, and NIIT by tax bracket and filing status, and total dividends reported and taxes on dividends paid by tax bracket and filing status.

Because the personal income tax brackets do not align with capital gains tax brackets or NIIT tax brackets, tax rates on qualified dividends (rows 2, 12, 22, and 32) and for the NIIT (rows 7, 17, 27, and 37) were distributed to personal income tax brackets assuming a uniform distribution. For example, if a personal income tax bracket ranged from adjusted gross incomes $100,000 to $200,000, the capital gains tax rate for filers with adjusted gross incomes of $100,000 to $150,000 was 15 percent and for filers with adjusted gross $150,000 to $200,000 the rate was 20 percent, the tax rate on qualified dividends for the $100,000 to $200,000 tax bracket would be 17.5 percent (under the assumption that half of the dividends would be on returns with income of $150,000 or less and would be taxed at 15 percent, and half would be on returns over $150,000 and would be taxed at 20 percent).

To calculate the overall federal tax rates on dividends, the total taxes paid on dividends were summed for each filing status (column J, rows 10, 20, 30, and 40), which was then divided by the total dividends for each filing status (column J, rows 9, 19, 29, and 39). That resulted in a 21.1 percent federal tax rate on each dollar of dividends, on average.

To determine the state dividend tax rates, the CIM and LCIM rely on a 2014 study conducted by the Tax Foundation, an independent tax policy nonprofit organization (Pomerleau 2014). Table 18 presents the state-specific rates from the Tax Foundation study along with the above estimate of the federal effective dividend income tax rate. Note that federal tax law allows households to deduct state and local taxes from their federal taxable income, though the 2017 Tax Cuts and Jobs Act capped this deduction at $10,000. Given the available data, it was not possible to determine the extent to which changes in dividend income would affect deductions for the purposes of estimating federal tax liability. As a result, the CIM and LCIM use the federal dividend income tax rate specified above (21.1 percent) with no adjustments. This may slightly overestimate federal tax revenues. However, the highest earners also report the bulk of dividend receipts and as a result, many will exceed the deduction cap; further, IRS data indicate that 80 percent of returns that reported less than $100,000 in adjusted gross income in 2015 took the standard

of Adjusted Gross Income and by Marital Status, Tax Year 2015 (Filing Year 2016), accessed at: https://www.irs.gov/statistics/soi-tax-stats-individual-statistical-tables-by-filing-status.

deduction, which would also mean they paid full taxes on any dividends they received.[51] As a result, any overestimation of federal dividend tax revenues in the CIM and LCIM are likely to be marginal.

To apply the dividend tax rates presented in Table 18, the CIM and LCIM first distribute dividend income to individual states. The models' allocation of this income to individual states is in proportion to interest, dividend, and net rental income in each state, based on data from the US Census Bureau's American Community Survey.

[51] See US Internal Revenue Service, Table 1.2. All Returns: Adjusted Gross Income, Exemptions, Deductions, and Tax Items, by Size of Adjusted Gross Income and by Marital Status, Tax Year 2015 (Filing Year 2016), accessed at: https://www.irs.gov/statistics/soi-tax-stats-individual-statistical-tables-by-filing-status.

Table 17. Summary of Federal Dividends and Dividend Taxes, by Filing Status and 2017 Tax Cuts and Jobs Act Personal Income Tax Bracket

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
		Tax Bracket (Up to...)							
Row		**$19,050**	**$77,400**	**$165,000**	**$315,000**	**$400,000**	**$600,000**	**Over $600,000**	**Total**
Married Joint Filers									
1	Qualified Dividends	$2,573,119	$6,960,662	$22,287,778	$20,475,968	$8,658,792	$13,490,045	$76,417,639	**$150,864,003**
2	Tax % on Qualified Dividends	0%	0%	15%	15%	15%	18%	20%	
3	Taxes Paid on Qualified Dividends	$0	$3,579	$3,343,167	$3,071,395	$1,298,819	$2,431,581	$15,283,528	**$25,432,068**
4	Nonqualified Dividends	$1,191,938	$3,072,814	$7,426,822	$5,756,068	$2,211,159	$3,408,678	$17,193,390	**$40,260,869**
5	Tax % on Nonqualified Dividends	10%	12%	22%	24%	32%	35%	37%	
6	Taxes Paid on Nonqualified Dividends	$119,194	$368,738	$1,633,901	$1,381,456	$707,571	$1,193,037	$6,361,554	**$11,765,451**
7	Net Investment Income Tax %				1.6%	3.8%	3.8%	3.8%	
8	**Net Investment Income Taxes Paid**				$431,954	$413,058	$642,151	$3,557,219	**$5,044,383**
9	**Total Dividends**	$3,765,057	$10,033,476	$29,714,600	$26,232,037	$10,869,951	$16,898,723	$93,611,028	**$191,124,872**
10	**Total Taxes Paid on Dividends**	$119,194	$372,316	$4,977,067	$4,884,806	$2,419,448	$4,266,770	$25,202,301	**$42,241,902**
Row		**$9,525**	**$38,700**	**$82,500**	**$157,500**	**$200,000**	**$300,000**	**Over $300,000**	**Total**
Married Separate Filers									
11	Qualified Dividends	$243,147	$174,781	$403,937	$319,274	$136,868	$99,806	$3,391,678	**$4,769,491**
12	Tax % on Qualified Dividends	0%	0%	15%	15%	15%	15%	20%	
13	Taxes Paid on Qualified Dividends	$0	$90	$60,591	$47,891	$20,530	$14,971	$671,918	**$815,990**
14	Nonqualified Dividends	$109,108	$89,959	$174,452	$109,527	$43,188	$25,487	$761,925	**$1,313,646**
15	Tax % on Nonqualified Dividends	10%	12%	22%	24%	32%	35%	37%	
16	Taxes Paid on Nonqualified Dividends	$10,911	$10,795	$38,379	$26,287	$13,820	$8,920	$281,912	**$391,025**
17	Net Investment Income Tax %				1.6%	3.8%	3.8%	3.8%	
18	**Net Investment Income Taxes Paid**				$7,061	$6,842	$4,761	$157,837	**$176,501**
19	**Total Dividends**	$352,255	$264,740	$578,389	$428,802	$180,056	$125,293	$4,153,603	**$6,083,138**
20	**Total Taxes Paid on Dividends**	$10,911	$10,885	$98,970	$81,239	$41,192	$28,652	$1,111,667	**$1,383,516**
Row		**$13,600**	**$51,800**	**$82,500**	**$157,500**	**$200,000**	**$500,000**	**Over $500,000**	**Total**
Head of Household Filers									
21	Qualified Dividends	$523,248	$2,177,823	$1,280,553	$1,217,689	$503,617	$887,782	$2,285,791	**$8,876,503**
22	Tax % on Qualified Dividends	0%	0%	15%	15%	15%	16%	20%	
23	Taxes Paid on Qualified Dividends	$0	$855	$192,083	$182,653	$75,542	$144,205	$457,158	**$1,052,498**
24	Nonqualified Dividends	$284,940	$1,106,322	$534,430	$419,359	$158,912	$226,709	$515,764	**$3,246,436**
25	Tax % on Nonqualified Dividends	10%	12%	22%	24%	32%	35%	37%	
26	Taxes Paid on Nonqualified Dividends	$28,494	$132,759	$117,575	$100,646	$50,852	$79,348	$190,833	**$700,506**
27	Net Investment Income Tax %						3.8%	3.8%	
28	**Net Investment Income Taxes Paid**						$42,351	$106,459	**$148,810**
29	**Total Dividends**	$808,187	$3,284,146	$1,814,983	$1,637,048	$662,529	$1,114,492	$2,801,556	**$12,122,940**
30	**Total Taxes Paid on Dividends**	$28,494	$133,614	$309,658	$283,300	$126,394	$265,904	$754,450	**$1,901,814**
Row		**$9,525**	**$38,700**	**$82,500**	**$157,500**	**$200,000**	**$500,000**	**Over $500,000**	**Total**
Single Filers									
31	Qualified Dividends	$2,125,982	$4,102,545	$6,035,020	$4,482,091	$1,984,965	$3,995,910	$11,946,233	**$34,672,746**
32	Tax % on Qualified Dividends	0%	0%	15%	15%	15%	16%	20%	
33	Taxes Paid on Qualified Dividends	$0	$2,109	$905,253	$672,314	$297,745	$648,803	$2,389,247	**$4,915,470**
34	Nonqualified Dividends	$1,089,398	$2,165,482	$2,624,484	$1,531,955	$626,339	$1,020,418	$2,687,418	**$11,745,493**
35	Tax % on Nonqualified Dividends	10%	12%	22%	24%	32%	35%	37%	
36	Taxes Paid on Nonqualified Dividends	$108,940	$259,858	$577,386	$367,669	$200,428	$357,146	$994,345	**$2,865,772**
37	Net Investment Income Tax %						3.8%	3.8%	
38	**Net Investment Income Taxes Paid**						$190,620	$556,079	**$746,699**
39	**Total Dividends**	$3,215,379	$6,268,027	$8,659,504	$6,014,046	$2,611,304	$5,016,328	$14,633,650	**$46,418,239**
40	**Total Taxes Paid on Dividends**	$108,940	$261,967	$1,482,639	$1,039,983	$498,173	$1,196,569	$3,939,670	**$8,527,942**

Table 18. Federal and State Dividend Tax Rates

State	Federal Rate	State Rate	State	Federal Rate	State Rate
Alabama	21.1%	5.0%	Montana	21.1%	6.9%
Alaska	21.1%	0.0%	Nebraska	21.1%	6.8%
Arizona	21.1%	4.5%	Nevada	21.1%	0.0%
Arkansas	21.1%	7.0%	New Hampshire	21.1%	5.0%
California	21.1%	13.3%	New Jersey	21.1%	9.0%
Colorado	21.1%	4.6%	New Mexico	21.1%	4.9%
Connecticut	21.1%	6.7%	New York	21.1%	8.8%
D.C.	21.1%	9.0%	North Carolina	21.1%	5.8%
Delaware	21.1%	6.6%	North Dakota	21.1%	3.2%
Florida	21.1%	0.0%	Ohio	21.1%	5.4%
Georgia	21.1%	6.0%	Oklahoma	21.1%	5.3%
Hawaii	21.1%	11.0%	Oregon	21.1%	9.9%
Idaho	21.1%	7.4%	Pennsylvania	21.1%	3.1%
Illinois	21.1%	5.0%	Rhode Island	21.1%	6.0%
Indiana	21.1%	3.4%	South Carolina	21.1%	7.0%
Iowa	21.1%	9.0%	South Dakota	21.1%	0.0%
Kansas	21.1%	4.8%	Tennessee	21.1%	6.0%
Kentucky	21.1%	6.0%	Texas	21.1%	0.0%
Louisiana	21.1%	6.0%	Utah	21.1%	5.0%
Maine	21.1%	8.0%	Vermont	21.1%	9.0%
Maryland	21.1%	5.8%	Virginia	21.1%	5.8%
Massachusetts	21.1%	5.2%	Washington	21.1%	0.0%
Michigan	21.1%	4.4%	West Virginia	21.1%	6.5%
Minnesota	21.1%	9.9%	Wisconsin	21.1%	7.7%
Mississippi	21.1%	5.0%	Wyoming	21.1%	0.0%
Missouri	21.1%	6.0%			

The dividend income remaining after the payment of both federal and state dividend taxes represents disposable income to US households. The CIM and LCIM assume that the entirety of this disposable income is spent by US households. Though it is possible that a portion would be saved (invested), exactly how it would be invested is uncertain. It could support investment in the US or overseas. Similarly, it could be invested in other industries or reinvested in the offshore oil and gas industry. Reinvestment in offshore oil and gas, however, would be reflected in the CIM's and LCIM's economic impact estimates related to industry expenditures in a subsequent year. Assuming that all domestic dividend income is spent by households simplifies the analysis of economic impacts related to dividend income and avoids potentially arbitrary assumptions about the investment behavior of dividend recipients.

5.5 Application of IMPLAN Multipliers

Following the methods described in the previous sections, the CIM and LCIM generate estimates of (1) expenditures of domestic dividend income by state, (2) corporate income tax collections by the federal government and state governments, and (3) dividend tax collections by the federal government and state governments. To estimate the economic impacts associated with the domestic expenditure of dividend income, the CIM and LCIM follow a three-step process.

- First, the CIM and LCIM allocate the dividend expenditures within each state to each household income group (as defined in IMPLAN) with annual income greater than $50,000 in proportion to each group's dividend income as obtained from IRS data (IRS 2017a).
- Second, to estimate the economic impacts of the expenditures made by each income group in each state, the CIM and LCIM apply state- and income group-specific income multipliers obtained from IMPLAN.
- Third, for the five states in the Gulf region, the CIM and LCIM also parse these impact estimates between individual EIAs and the five rest-of-state areas. For each of these states, the CIM and LCIM allocate economic impacts between these areas in proportion to each area's share of dividend income in the state, as obtained from county level data reported by the IRS (2017b).

To estimate the economic impacts of federal and state government expenditures of dividend and corporate income tax revenues, the CIM and LCIM use the same approach described in Section 4.4 regarding the economic impacts associated with the expenditure of OCS royalty, rent, and bonus revenues.

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Appendix A Timing and Frequency of OCS Oil & Gas Lease Activity in the LCIM

A.1 Introduction

The economic and fiscal impacts associated with a lease or group of leases depend on when various oil and gas activities occur on the lease(s) in question and the frequency of occurrence for these activities (e.g., the number of exploratory wells drilled). The frequency of activity affects the overall magnitude of economic impacts (e.g., more wells drilled corresponds to greater impacts, all else equal). In addition, the timing of activity matters for expressing both costs and revenues in present value terms, which is important for assessing the financial viability of a lease or group of leases.

The LCIM is designed to use timing and frequency information obtained in one of two ways for a given scenario:

1. Under the first approach, the user populates a detailed leasing scenario spreadsheet that includes the exact frequency and timing of activities (e.g., the number of exploratory wells drilled by year). After completing this spreadsheet, the user imports the scenario data into the model. Thus, under this approach, timing and frequency information for individual OCS activities is provided directly by the user.
2. Under the second approach, the user enters a smaller volume of information for the scenario via a streamlined leasing scenario interface within the LCIM. Using the more limited user-provided data in conjunction with various historical data that reside in the model for specific activities, the LCIM generates a time series of OCS oil and gas activities for the leasing scenario. This approach places less of a data entry burden on the user but assumes that the distribution of activity over time and the frequency of activity on a lease is consistent with historical data.

The purpose of this appendix is to document these two approaches and the corresponding supporting data. The chapter begins by summarizing the variables for which the LCIM requires timing and frequency information. We then describe the LCIM's use of the detailed leasing scenario spreadsheet. Following this discussion, we describe how the LCIM uses information provided via the streamlined leasing scenario interface in conjunction with the historical data that reside in the model.

A.2. Variables for which the LCIM Requires Timing and Frequency information

As mentioned above, the LCIM requires information on the timing and frequency of OCS activities to estimate costs and revenues in present value terms and to accurately estimate economic impacts for a given year. Table A-1 lists each of the activities for which the model requires timing and/or frequency information and summarizes the impact of activity timing and frequency on model results.

Table A-1. Summary of Activities Requiring Timing and/or Frequency Information

Activity Time Series	Impact of Timing and Frequency in Model
Exploratory well drilling	The number of exploratory wells drilled affects the magnitude of well drilling costs and the economic impacts associated with well drilling. The timing of exploratory well drilling affects the present value of well drilling costs.
Development well drilling	The number of development wells drilled affects the magnitude of well drilling costs and the economic impacts associated with well drilling. The timing of development well drilling affects the present value of well drilling costs.
Structure installation	The number of structures installed affects the magnitude of structure installation costs and the economic impacts associated with structure installation. Because the LCIM assumes that the number of structures removed for a lease or group of leases is equal to the number installed, the number of structures installed also affects the costs and economic impacts associated with structure removal. The timing of structure installation affects the present value of structure installation costs.
Number of structures in operation (O&M)	The number of operational structures associated with a lease in a given year affects the magnitude of production O&M costs and the economic impacts associated with OCS operations.
Structure removal	The timing of structure removal affects the present value of structure removal costs. The number of structures removed is assumed to be the same as the number installed.
Pipeline installation (miles of pipeline installed)	The miles of pipeline installed affects the magnitude of both pipeline installation costs and the economic impacts associated with pipeline installation. The timing of pipeline installation affects the present value of pipeline installation costs.
Oil and gas production	The timing of production affects the present value of revenues and production O&M costs (i.e., O&M costs are assumed only for years with production). The timing of production also impacts how capital costs are spread over time for the purposes of estimating the profit-related impacts presented in Chapter 5.

A.3 Timing and Frequency of OCS Activities Provided by the Detailed Leasing Scenario Spreadsheet

The detailed leasing scenario spreadsheet allows the user to input the specific timing and frequency of all OCS activity associated with an individual lease or group of leases. The format of the spreadsheet is similar to the format of the E&D scenario spreadsheets developed by BOEM in support of the National OCS Leasing Program. The spreadsheet requires the user to manually enter the following inputs by year and water depth category (except for pipelines and production estimates):

- Exploratory & appraisal wells drilled (# of wells)
- Non-producing wells drilled (# of wells)
- "Production" wells – exploration wells re-entered and completed (# of wells)
- "Production" wells – development wells drilled and completed (# of wells)
- Single well structures installed (# of structures)
- Single well structures in operation (# of structures)
- Single well structures removed (# of structures)
- Multi-well structures installed (# of structures)
- Multi-well structures in operation (# of structures)
- Multi-well structures removed (# of structures)
- "Structure" type – TLP, SPAR, SEMI installed (# of subsea)
- "Structure" type – TLP, SPAR, SEMI in operation (# of subsea)
- "Structure" type – TLP, SPAR, SEMI removed (# of subsea)
- FPSO installed (water depth >1600m only) (# of FPSO)
- FPSO in operation (water depth >1600m only) (# of FPSO)
- FPSO removed (water depth >1600m only) (# of FPSO)
- "Structure" type – SUBSEA system installed (# of structures)
- "Structure" type – SUBSEA system in operation (# of structures)
- "Structure" type – SUBSEA system removed (# of structures)
- Pipelines (miles installed)
- Oil Production Total (bbls)
- Gas Production Total (Mcf)
- Total Revenues – Bonus ($ millions)
- Total Revenues – Rent ($ millions)
- Total Revenues – Royalty ($ millions)
- Total Revenues – Total ($ millions)
- 8(g) Revenues – Bonus ($ millions)
- 8(g) Revenues – Rent ($ millions)

- 8(g) Revenues – Royalty ($ millions)
- 8(g) Revenues – Total ($ millions)
- GOMESA Revenues – Bonus ($ millions)
- GOMESA Revenues – Rent ($ millions)
- GOMESA Revenues – Royalty ($ millions)
- GOMESA Revenues – Total ($ millions)
- Non-GOMESA Revenues – Bonus ($ millions)
- Non-GOMESA Revenues – Rent ($ millions)
- Non-GOMESA Revenues – Royalty ($ millions)
- Non-GOMESA Revenues – Total ($ millions)

After providing these inputs, the user imports the detailed leasing scenario spreadsheet into the LCIM, as described in detail in the LCIM User Guide.

A.4 Timing and Frequency of OCS Activities Derived from the Streamlined Leasing Scenario Interface

As an alternative to providing the relatively large amount of data required for the detailed leasing scenario spreadsheet , LCIM users may use the streamlined leasing scenario interface in the model itself to define individual leasing scenarios. This interface requires a limited number of data inputs from the user, including but not limited to the following:

- Lease water depth
- Lease issuance year
- Number of leases (for multi-lease scenarios only)
- Total oil and gas production over the life of the lease (or group of leases).

The streamlined leasing scenario interface also requires the user to select which percentile to use from the statistical distributions stored in the model regarding (1) the number of years before a given OCS oil and gas activity begins following lease issuance, (2) the frequency of occurrence for each activity, and (3) the number of years between the first and last occurrence of the activity (e.g., years between the first and last years when exploratory wells are drilled). As described in more detail below, these distributions were developed based on the timing and frequency of OCS activities observed in historical activity datasets from the BOEM Data Center. The model user may select the average (mean) value observed in the historical lease data or values that match the 10th, 25th, 50th, 75th, or 90th percentiles in the historical data. The user makes this selection separately for timing versus the frequency of activity. When the user selects the percentiles for a given water depth category, the model applies those percentile values for all activities for that depth category. For example, if the user selects the 50th percentile for the frequency of activity and the 75th percentile for timing, the LCIM will forecast the frequency of *all* OCS activities for that water depth category based on observed data for historical leases with 50th percentile frequency characteristics. Similarly, the model will forecast the timing of all OCS activities for that water depth category based on time series observed for historical leases with 75th percentile timing characteristics.

Table A-2 identifies the time series projected by the LCIM based on the information provided by users via the streamlined leasing scenario interface and the distributions that reside in the model. For each time series, the table also shows the information that the model relies upon from the streamlined leasing scenario interface and the information used from the historical data included in the model. Using this information, the LCIM generates each time series based on the procedures summarized in the last column of Table A-2.

Table A-2. Summary of LCIM Data and Procedures for Developing Activity Projections from Streamlined Leasing Scenario Interface

Time Series Projected from User-Provided Data and Historical Data	Information Used from Streamlined Leasing Scenario Interface	Historical Data Used for Time Series	Steps for Projecting Each Time Series
Exploratory well drilling[1]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Years before first exploratory well drilled, by water depth (E) Number of exploratory wells per lease, by water depth (F) Proportion of exploratory wells re-entered and completed, by water depth (G) Years between first and last exploratory wells, by water depth (H)	Identify calendar year of first exploratory well drilled based on A, C, D, and E (value for E dependent on A and D). Identify number of exploratory wells drilled per lease based on A, D, and F (value of F dependent on A and D). Identify the number of exploratory wells re-entered and completed per lease based on F and G. Estimate number of years over which exploratory wells drilled based on A, D, and H (value of H dependent on B and D). Based on this and calendar year of the first exploratory well drilled, identify the calendar years over which exploratory wells are drilled. Distribute the number of exploratory wells drilled per lease uniformly over the calendar years identified. For each year, calculate total number of exploratory wells drilled by multiplying wells drilled per lease per year (from previous bullet) by B.

Time Series Projected from User-Provided Data and Historical Data	Information Used from Streamlined Leasing Scenario Interface	Historical Data Used for Time Series	Steps for Projecting Each Time Series
Development well drilling[2]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Years before first development well drilled, by water depth (I) Number of development wells per lease, by water depth (J) Proportion of developments wells completed vs non-producing, by water depth (K) Years between first and last development wells, by water depth (L)	Same process as described above for exploratory wells, but using variables I, J, K, and L instead of E, F, G, and H, respectively.
Structure installation[3]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Years before first structure installation, by water depth (M) Number of structures installed per lease, by water depth (N) Years between first and last structure installations, by water depth (O)	Same process as described above for exploratory wells, but using variables M, N, and O instead of E, F, and H, respectively.
Structure operation (O&M)[4]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Number of structures installed per lease, by water depth (N) Years before production begins, by water depth (P)	Identify number of structures installed per lease based on A, D, and N (value of N dependent on A and D). Identify calendar year of first production based on A, C, D, and P (value for P dependent on A and D). Assign structure operation to each structure installed per lease in the calendar year of first production and the subsequent 30 years. For each year, calculate total number of operating structures by multiplying operating structures per lease per year (from previous bullet) by B.

Time Series Projected from User-Provided Data and Historical Data	Information Used from Streamlined Leasing Scenario Interface	Historical Data Used for Time Series	Steps for Projecting Each Time Series
Structure removal[5]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Number of structures installed per lease, by water depth (N) Years before production begins, by water depth (P)	Identify number of structures installed per lease based on A, D, and N (value of N dependent on A and D). Identify calendar year of first production based on A, C, D, and P (value for P dependent on A and D). Assign structure removal to each structure installed per lease 31 years after the calendar year of first production. For each year, calculate total number of removed structures by multiplying structures removed per lease per year (from previous bullet) by B.
Pipeline installation[6]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D)	Years before pipeline installation, by water depth (Q) Miles of pipeline installed per lease, by water depth (R)	Identify calendar year of first pipeline installation based on A, C, D, and Q (value for Q dependent on A and D). Identify miles of pipeline installed per lease based on A, D, and R (value of R dependent on A and D). Assign the miles of pipeline installed per lease to the calendar year of first pipeline installation. For each year, calculate total miles of pipeline installed by multiplying miles of pipeline installed per lease per year (from previous bullet) by B.
Production[7]	Water depth (A) Number of leases, by water depth (B) Lease issuance year (C) Percentile chosen by user, by water depth (D) Oil production over the life of the new leases (S) Gas production over the life of the new leases (T)	Years before production begins, by water depth (P) Distribution of production over time, by water depth (U)	Identify calendar year of first production based on A, C, D, and P (value for P dependent on A and D). Estimate production of oil and gas in each year based on S, T, and U (value of U dependent on A).

Time Series Projected from User-Provided Data and Historical Data	Information Used from Streamlined Leasing Scenario Interface	Historical Data Used for Time Series	Steps for Projecting Each Time Series
Notes: Exploratory well drilling includes each of the following from Section A.3 above: Exploratory & appraisal wells drilled (# of wells), “Production” wells – exploration wells re-entered and completed (# of wells) Development well drilling includes each of the following from Section A.3 above: Non-producing wells drilled (# of wells), “Production” wells – development wells drilled and completed (# of wells) Structure installation includes each of the following from Section A.3 above: Single well structures installed (# of structures), Multi-well structures installed (# of structures), “Structure” type – TLP, SPAR, SEMI installed (# of subsea), FPSO installed (water depth >1600m only) (# of FPSO), “Structure” type – SUBSEA system installed (# of structures) Structure operation (O&M) includes each of the following from Section A.3 above: Single well structures in operation (# of structures), Multi-well structures in operation (# of structures), “Structure” type – TLP, SPAR, SEMI in operation (# of subsea), FPSO in operation (water depth >1600m only) (# of FPSO), “Structure” type – SUBSEA system in operation (# of structures) Structure removal includes each of the following from Section A.3 above: Single well structures removed (# of structures), Multi-well structures removed (# of structures), “Structure” type – TLP, SPAR, SEMI removed (# of subsea), FPSO removed (water depth >1600m only) (# of FPSO), “Structure” type – SUBSEA system removed (# of structures) Pipeline installation includes each of the following from Section A.3 above: Pipelines (miles installed) Production includes each of the following from Section A.3 above: Oil Production Total (bbls), Gas Production Total (Mcf)			

The statistical distributions that the LCIM uses to produce the activity time series summarized in Table A-2 were developed based on historical activity datasets from the BOEM Data Center. Table A-3 summarizes the datasets and calculation steps used to develop each distribution. All of the distributions rely on historical activity data for leases initiated between 1985 and 2005. We did not include leases initiated after 2005 because development activities are unlikely to have commenced on all of these leases. As a result, any distributions calculated based on more recent leases would be biased, since the only available activity data will be associated with leases with shorter than average development cycles. We selected 1985 as the start date to ensure that we had a sufficient sample size of leases to calculate representative distributions, while excluding older leases likely associated with outdated technology and development patterns.

Table A-3. Sources of Historical Activity Data Used for Estimation of Statistical Distributions

Time Series	Distribution	BOEM Data Center Datasets	Calculation Notes
Exploratory well drilling	Years before first exploratory well	Borehole[1], Leases[2]	Calculated for each lease based on the number of days between the *Lease Effective Date* and the earliest *Spud Date* for a well with *Type Code* "E".
	Number of exploratory wells per lease	Borehole	Calculated by counting the number of wells with *Type Code* "E" associated with each lease.
	Years between first and last exploratory wells	Borehole	Calculated for each lease based on the number of days between the earliest and latest *Spud Date* for wells with *Type Code* "E".
	Number of exploratory wells re-entered and completed per lease	Borehole	Calculated by multiplying the number of exploratory wells per lease by the ratio of exploratory wells re-entered and completed to total exploratory wells drilled across all years of BOEM's 2017 to 2022 GOM Cumulative Case E&D Scenario associated with the Bureau's 2017-2022 National OCS Leasing Program.
Development well drilling	Years before first development well	Borehole[1], Leases[2]	Calculated for each lease based on the number of days between the *Lease Effective Date* and the earliest *Spud Date* for a well with *Type Code* "D".
	Number of development wells per lease	Borehole	Calculated by counting the number of wells with *Type Code* "D" associated with each lease.
	Years between first and last development wells	Borehole	Calculated for each lease based on the number of days between the earliest and latest *Spud Date* for wells with *Type Code* "D".

Time Series	Distribution	BOEM Data Center Datasets	Calculation Notes
	Number of development wells completed per lease	Borehole	Calculated by multiplying the number of development wells per lease by the ratio of development wells completed (versus non-producing) to total development wells drilled across all years of BOEM's 2017 to 2022 GOM Cumulative Case E&D Scenario associated with the Bureau's 2017-2022 National OCS Leasing Program.
Structure installation	Years before first structure installation	Platform Structure[3], Leases[2]	Calculated for each lease based on the number of days between the *Lease Effective Date* and the earliest *Install Date*.
	Number of structures installed per lease	Platform Structure	Calculated by counting the number of structures associated with each lease.
	Years between first and last structure installations	Platform Structure	Calculated based on the number of days between the earliest and latest *Install Date* for structures associated with each lease.
Pipeline installation	Years before pipeline installation	Pipeline Masters[4], Leases[2]	Calculated for each lease based on the number of days between the *Lease Effective Date* and the earliest *Install Date*.
	Miles of pipeline installed per lease	Pipeline Masters	Calculated by summing the *Segment Length* for all pipelines originating from each lease.
Production	Years before production begins	Leases	Calculated for each lease based on the number of days between the *Lease Effective Date* and the *First Production Date*.
	Distribution of production over time	Production[5]	Calculated based on the percentage of lifetime production (measured as barrel of oil equivalents) that occurs on each lease in each year following the first year with production.

Sources:

BOEM Data Center. "Borehole." https://www.data.boem.gov/Well/Files/BoreholeRawData.zip
BOEM Data Center. "Leases." https://www.data.boem.gov/Leasing/Files/lsetapefixed.zip
BOEM Data Center. "Platform Structures." https://www.data.boem.gov/Platform/Files/PlatStrucRawData.zip
BOEM Data Center. "Pipeline Masters." https://www.data.boem.gov/Pipeline/Files/pplmastdelimit.zip
BOEM Data Center. "Production." https://www.data.boem.gov/Production/Files/ProductionRawData.zip

Table A-4 presents the distributions for each of the relevant OCS activities. The table includes separate estimates of timing and frequency for each OCS activity by water depth category and relative temporal distribution (average, 10th percentile, 25th percentile, 50th percentile, 75th percentile, 90th percentile). For example, the “Years before exploratory well table” lists a value of 2.4 for the 200-800m water depth and 50th percentile. This indicates that historical leases at the 50th percentile drilled their first exploratory well 2.4 years after lease issuance. At the 75th percentile for the same water depth, historical leases drilled their first exploratory well 4.6 years after lease issuance. Though the values are presented out to one decimal place in the table, all values representing the number of years are rounded to the nearest integer upon import into the LCIM for modeling purposes. Data representing the number of wells, number of structures, or miles of pipeline are incorporated into the LCIM as shown in Table A-4 (i.e., with no rounding). Also, Table A-5 presents the temporal distribution of total production over the life of historical leases.

Table A-4. LCIM Activity Distributions

Water Depth	Years before exploratory well					
	Avg.	10%	25%	50%	75%	90%
0–60m	2.3	0.4	0.8	1.8	4.0	4.9
60–200m	2.6	0.5	0.9	2.2	4.6	5.0
200–800m	2.7	0.5	0.9	2.4	4.6	5.0
800–1600m	5.8	1.0	2.3	5.0	9.4	10.4
1600m+	7.2	1.4	3.1	7.3	10.1	12.3

Water Depth	Years before development well					
	Avg.	10%	25%	50%	75%	90%
0–60m	3.4	0.5	1.3	3.3	5.0	7.8
60–200m	3.6	0.4	1.5	3.7	5.3	6.8
200–800m	5.3	1.0	3.1	4.8	7.3	9.8
800–1600m	8.0	1.6	3.6	8.0	11.3	13.2
1600m+	10.0	2.4	4.3	10.0	14.6	17.1

Water Depth	Number of exploratory wells					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.8	1.0	1.0	1.0	2.0	3.0
60–200m	2.2	1.0	1.0	1.0	2.0	4.0
200–800m	2.1	1.0	1.0	1.0	2.0	4.0
800–1600m	3.0	1.0	1.0	2.0	3.0	6.0
1600m+	2.8	1.0	1.0	2.0	3.0	7.0

Water Depth	Number of development wells					
	Avg.	10%	25%	50%	75%	90%
0–60m	2.8	1.0	1.0	2.0	3.0	6.0
60–200m	4.1	1.0	1.0	2.0	4.0	8.0
200–800m	4.3	1.0	1.0	2.0	5.0	10.0
800–1600m	4.6	1.0	1.0	2.0	6.0	13.3
1600m+	4.2	1.0	1.0	2.0	4.0	11.0

Water Depth	Years between first and last exploratory well					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.1	0.0	0.0	0.0	0.6	8.0
60–200m	1.1	0.0	0.0	0.0	0.6	9.1
200–800m	1.3	0.0	0.0	0.0	0.4	5.7
800–1600m	2.0	0.0	0.0	0.2	1.4	9.2
1600m+	2.4	0.0	0.0	0.4	2.1	8.7

Water Depth	Years between first and last development well					
	Avg.	10%	25%	50%	75%	90%
0–60m	2.6	0.0	0.0	1.0	3.8	22.0
60–200m	3.5	0.0	0.0	0.6	4.2	20.6
200–800m	3.7	0.0	0.0	0.5	3.8	17.7
800–1600m	4.0	0.0	0.0	1.0	3.9	16.3
1600m+	3.8	0.0	0.0	1.3	3.2	11.1

Water Depth	Number of exploratory wells re-entered and completed					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.1	0.0	0.0	0.0	0.6	8.0
60–200m	1.1	0.0	0.0	0.0	0.6	9.1
200–800m	1.3	0.0	0.0	0.0	0.4	6.5
800–1600m	2.0	0.0	0.0	0.0	0.6	7.9
1600m+	2.4	0.0	0.0	0.0	0.4	5.8

Water Depth	Number of development wells completed					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.7	0.0	0.0	0.6	2.4	14.2
60–200m	2.1	0.0	0.0	0.4	2.6	12.8
200–800m	2.3	0.0	0.0	0.3	2.4	11.1
800–1600m	2.5	0.0	0.0	0.6	2.4	10.2
1600m+	2.4	0.0	0.0	0.8	2.0	7.0

Water Depth	Years before structure installation					
	Avg.	10%	25%	50%	75%	90%
0–60m	2.6	0.6	1.2	2.7	4.7	5.6
60–200m	3.7	1.1	1.9	4.0	6.0	7.0
200–800m	7.0	3.6	4.2	7.2	9.8	10.2
800–1600m	10.6	5.1	7.1	11.2	13.8	15.2
1600m+	10.0	2.7	4.4	11.0	15.1	16.8

Water Depth	Average Years before Pipeline Installation					
	Avg.	10%	25%	50%	75%	90%
0–60m	3.8	1.1	1.9	3.5	5.4	6.2
60–200m	4.5	1.4	2.1	4.1	6.2	7.2
200–800m	5.5	1.5	2.9	5.0	7.0	9.9
800–1600m	10.5	3.8	6.4	10.2	13.7	17.0
1600m+	12.6	4.8	9.0	13.0	16.4	18.8

Water Depth	Number of structures					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.4	1.0	1.0	1.0	1.0	2.0
60–200m	1.2	1.0	1.0	1.0	1.0	1.0
200–800m	1.1	1.0	1.0	1.0	1.0	1.6
800–1600m	1.1	1.0	1.0	1.0	1.0	1.1
1600m+	1.0	1.0	1.0	1.0	1.0	1.0

Water Depth	Miles of pipeline installed					
	Avg.	10%	25%	50%	75%	90%
0–60m	6.2	0.9	2.1	3.9	7.1	12.4
60–200m	11.1	1.6	2.9	5.2	10.5	19.2
200–800m	24.4	2.9	6.9	13.6	26.7	47.2
800–1600m	33.6	1.5	5.5	14.8	41.7	106.8
1600m+	29.7	0.4	4.6	14.4	32.2	81.9

Water Depth	Years between first and last structure					
	Avg.	10%	25%	50%	75%	90%
0–60m	1.2	0.0	0.0	0.0	0.0	10.2
60–200m	0.3	0.0	0.0	0.0	0.0	2.8
200–800m	0.6	0.0	0.0	0.0	0.0	4.0
800–1600m	0.9	0.0	0.0	0.0	0.0	17.0
1600m+	0.0	0.0	0.0	0.0	0.0	0.0

Water Depth	Years before production begins					
	Avg.	10%	25%	50%	75%	90%
0–60m	3.7	1.1	1.9	3.5	5.4	6.1
60–200m	4.4	1.4	2.3	4.4	6.2	7.1
200–800m	5.6	1.7	3.8	5.3	7.2	9.8
800–1600m	10.7	4.0	7.0	11.1	14.0	16.1
1600m+	13.0	5.6	9.0	13.6	17.2	20.8

Table A-5. LCIM Production Distributions

Years Since Production Start Date	Percent of Total Production (BOE) by Year				
	0–60m	60–200m	200–800m	800–1600m	1600m+
0	9.0%	7.4%	1.5%	1.5%	1.5%
1	16.6%	13.2%	5.1%	5.1%	5.1%
2	12.2%	10.5%	5.7%	5.7%	5.7%
3	9.0%	8.9%	7.4%	7.4%	7.4%
4	6.8%	7.1%	8.1%	8.1%	8.1%
5	5.5%	6.0%	7.3%	7.3%	7.3%
6	4.6%	5.1%	6.0%	6.0%	6.0%
7	3.7%	4.2%	5.2%	5.2%	5.2%
8	3.2%	4.0%	4.2%	4.2%	4.2%
9	2.9%	3.4%	3.3%	3.3%	3.3%
10	2.6%	3.0%	3.2%	3.2%	3.2%
11	2.4%	2.6%	3.0%	3.0%	3.0%
12	2.1%	2.4%	3.4%	3.4%	3.4%
13	1.9%	2.2%	4.9%	4.9%	4.9%
14	1.7%	2.0%	3.7%	3.7%	3.7%
15	1.7%	2.0%	2.6%	2.6%	2.6%
16	1.6%	1.9%	3.0%	3.0%	3.0%
17	1.4%	1.8%	5.3%	5.3%	5.3%
18	1.2%	1.8%	3.2%	3.2%	3.2%
19	1.2%	1.5%	2.7%	2.7%	2.7%
20	1.2%	1.4%	2.6%	2.6%	2.6%
21	1.1%	1.3%	3.2%	3.2%	3.2%
22	1.0%	1.1%	1.3%	1.3%	1.3%
23	0.9%	1.0%	1.1%	1.1%	1.1%
24	0.9%	0.8%	0.7%	0.7%	0.7%
25	0.8%	0.7%	0.6%	0.6%	0.6%
26	0.7%	0.7%	0.5%	0.5%	0.5%
27	0.6%	0.6%	0.4%	0.4%	0.4%
28	0.5%	0.5%	0.3%	0.3%	0.3%
29	0.5%	0.4%	0.3%	0.3%	0.3%
30	0.4%	0.4%	0.2%	0.2%	0.2%

Sources:

BOEM. "Production Data." Accessed at: https://www.data.boem.gov/Main/RawData.aspx
BOEM. "Lease Data." Accessed at: https://www.data.boem.gov/Main/Leasing.aspx

Table A-6 illustrates how the LCIM applies the information from the streamlined input interface and the activity distributions to create a lease activity timeline. The example in the table is based on a lease in 800-1600m water depth, with a lease issuance year of 2020, 50th percentile frequency *and* timing distributions, 100,000 bbl of oil production, and 50,000 Mcf of gas production. The calculations for each of the separate time series are explained below.

- **Exploratory Wells Drilled**. Table A-4 indicates that there are five years between lease issuance and exploratory well drilling for 50th percentile leases[52] in 800-1600m water depth. Additionally, there is only one well per lease at the 50th percentile in this water depth. As a result, the time series below indicates that one exploratory well will be drilled in 2025, five years after lease issuance.
- **Development Wells Drilled**. Table A-4 indicates that 50th percentile leases in 800–1600m water depths have two development wells, drilled one year apart, with the first drilled eight years after lease issuance. As a result, the time series below shows one development well drilled in 2028 and one in 2029.
- **Structures Installed.** Table A-4 indicates that 50th percentile leases in 800-1600m water depths have one structure installed 11 years after lease issuance. As a result, the time series below shows one structure installed in 2031.
- **Structures Operating (O&M).** We did not calculate separate distributions related to structure operation. Instead, we assume that all previously installed structures are operating (and receive O&M costs) in years with oil and gas production. Production on this example lease begins in 2031 and ends in 2061 (see below). As a result, we assume that the structure installed in 2031 is operating in each of those years.
- **Structures Removed.** We did not calculate separate distributions related to structure removal. Instead, we assume that removal of all structures occurs the year after production ends on a lease. Because production ends in 2061 on this example lease, we assume that the one structure is removed in 2062.
- **Miles of Pipeline Installed**. Table A-4 indicates that 50th percentile leases in 800–1600m water depths have 14.8 miles of pipeline installed 10 years after lease issuance. As a result, the time series below shows 14.8 miles of pipeline installed in 2030.
- **Production (BOE)**. Table A-4 indicates that 50th percentile leases in 800-1600m water depths begin production 11 years after lease issuance. As a result, the time series below shows production beginning in 2031. The quantity of oil and gas produced in each year is a function of the total oil and gas production selected by the user as well as the percentage of total BOE production occurring in each year presented in Table A-5 for leases in 800–1600m water depth.

[52] For purposes of exposition here, the term "50th percentile leases" here refers to leases at the 50th percentile with respect to both the frequency of OCS oil and gas activity *and* the timing of such activity.

Table A-6. Example Lease Time Series Based on Distributions

Inputs From Streamlined Leasing Scenario Spreadsheet

Water Depth	800-1600m
Lease issuance year	2020
Temporal distribution of activity	50th percentile
Oil production over the life of the new leases (barrels)	100,000
Gas production over the life of the new leases (Mcf)	50,000

Time Series

Year	Exploratory Wells Drilled	Development Wells Drilled	Structures Installed	Structures Operating (O&M)	Structures Removed	Miles of Pipeline Installed	Production (BOE)
2020							
2021							
2022							
2023							
2024							
2025	1						
2026							
2027							
2028		1					
2029		1					
2030						14.8	
2031			1	1			1,644
2032				1			5,513
2033				1			6,226
2034				1			8,078
2035				1			8,776
2036				1			7,937
2037				1			6,531
2038				1			5,700
2039				1			4,536

Year	Exploratory Wells Drilled	Development Wells Drilled	Structures Installed	Structures Operating (O&M)	Structures Removed	Miles of Pipeline Installed	Production (BOE)
2040				1			3,573
2041				1			3,491
2042				1			3,233
2043				1			3,742
2044				1			5,308
2045				1			4,075
2046				1			2,847
2047				1			3,232
2048				1			5,788
2049				1			3,487
2050				1			2,931
2051				1			2,810
2052				1			3,491
2053				1			1,415
2054				1			1,165
2055				1			797
2056				1			617
2057				1			534
2058				1			421
2059				1			346
2060				1			318
2061				1			272
2062					1		

Note that the time series distributions presented above do not directly correspond to each of the OCS activities listed in Section 2.3. In particular, some of the time series distributions are inclusive of multiple activities from Section 2.3. For example, the structures installed time series reflects structure installations across all structure types. However, for some water depths there are multiple structure types which correspond to different costs in the LCIM. We were unable to calculate separate time series distributions for each of these structure types because the sample sizes would have been too small to develop reliable estimates. As a result, the LCIM applies assumptions about the percentage of total structures installed by water depth that correspond to different structure types. Specifically, the LCIM relies on the relative proportion of structure types by water depth observed across all years of BOEM’s 2017 to 2022 GOM Cumulative Case E&D Scenario associated with BOEM’s 2017–2022 National OCS Leasing Program.

Additionally, some of the activities listed in Section A.3 are not tracked directly in BOEM datasets. For instance, the BOEM Data Center dataset on well drilling does not track which exploratory wells are re-entered and completed and which development wells are non-producing (versus completed and producing). As a result, the LCIM relies on assumptions about the average proportion of exploratory wells that are re-entered and completed and average proportion of development wells that are producing versus non-producing. As with structures, the LCIM relies on the proportions observed across all years of BOEM’s 2017 to 2022 GOM Cumulative Case E&D Scenario. Specifically, the LCIM assumes that 39 to 66 percent of exploratory wells are re-entered and completed and 36 to 38 percent of development wells are non-producing (varying based on water depth). For exploratory wells that are re-entered and completed, the LCIM assumes that the wells are re-entered and completed in the same year that they are initially drilled.

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 the 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 communities.

The Bureau of Ocean Energy Management

The Bureau of Ocean Energy Management (BOEM) works to manage the exploration and development of the nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.

www.boem.gov