OCS Study
BOEM 2012-102

MAG-Plan 2012
Economic Impact Model for the Gulf of Mexico-Updated and Revised Data

U.S. Department of the Interior
Bureau of Ocean Energy Management
Gulf of Mexico OCS Region

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 EXECUTIVE SUMMARY

1.1 PURPOSE

The Bureau of Ocean Energy Management (BOEM) plays a key role in the U.S.'s energy supply by managing the mineral resources on nearly 160 million acres in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) region. Under the National Environmental Policy Act (NEPA), BOEM is required to integrate environmental values into its decision-making processes. BOEM does this by preparing Environmental Impact Statements and other analyses that examine the effects of its proposed actions and reasonable alternatives to those actions. BOEM prepares site-specific and Gulf-wide analyses to support the five-year schedule of federal oil and gas leasing required by the Outer Continental Shelf Lands Act (43 U.S.C. 1344).

To support these analyses, BOEM (then known as the Minerals Management Service, or MMS) developed MAG-PLAN, a two-stage input-output model to estimate employment, personal income, and similar economic impacts from OCS activities (USDOI MMS 2005). MAG-PLAN's Stage 1 starts with BOEM estimates of the level of exploration, development, production, and infrastructure associated with a proposed OCS lease sale or set of sales. The model allocates industry expenditures among IMPLAN industry sectors[1] and then distributes the expenditure-by-sector spending to onshore areas. Stage 2 uses region-specific IMPLAN multipliers to calculate the jobs, earnings, and output resulting from oil and gas operations in the GOM OCS.

The purpose of this project is to update the data to:

- Reflect new developments in technologies, such as floating and subsea production systems.
- Incorporate new costs[2] for major activities. (All costs are presented in thousands of 2008).
- Incorporate detailed onshore distribution data for key offshore oil and gas activities.
- Develop a methodology to estimate the onshore distribution of other industry sectors at different levels of granularity (i.e., national, state, or regional).

[1] IMPLAN (IMpact Analysis for PLANning) is an input-output analysis (I-O) software package with modeling and data components. I-O is a means of examining relationships within an economy, both between businesses and between businesses and final consumers that captures all monetary market transactions for consumption in a given time period. The resulting mathematical formulae allow examination of the effects of a change in one or several economic activities on an entire economy (impact analysis). IMPLAN v.3 disaggregates the U.S. economy into 440 industry sectors and can be used to estimate change in employment (jobs), output, and earnings from increases or decreases in economic activity. IMPLAN industry sectors are consistent with NAICS codes; see http://implan.us/v3/index.php?option=com_docman&task=cat_view&gid=145&Itemid=138 for crosswalk tables.

[2] MAG-PLAN models industry expenditures, which in some cases may be slightly different than industry costs. However, for the purpose of this report the two terms are used interchangeably.

1.2 REPORT ORGANIZATION

The report is organized as follows:

- Chapter 2.0 provides an overview of MAG-PLAN and covers basic concepts, logic flow, and other general information.
- Chapter 3.0 presents the expenditure data and supporting sources. For new activity functions developed for MAG-PLAN 2012 (i.e., geological and geophysical prospecting; Floating, Production, Storage, and Offloading [FPSOs]; and subsea systems), Chapter 3 also discusses the allocation of those costs among the 440 IMPLAN sectors.
- Chapter 4.0 discusses the methodology used to estimate the percentage of total expenditures formed by payments to labor.
- Chapter 5.0 focuses on the "onshore distribution" methodology, which traces how labor and non-labor expenditures flow from the offshore regions to onshore regions in the GOM.
- Chapter 6.0 describes revenue functions and how they are incorporated within MAG-PLAN.
- Chapter 7.0 discusses the strengths and weaknesses of MAG-PLAN 2012.

This report focuses on methodology and data; a separate user's manual focuses on the software requirements, model structure, and instructions for running the model.

2.0 INTRODUCTION

2.1 HISTORY

The Outer Continental Shelf Lands Act (OCSLA), as amended, established a policy for the management of oil and natural gas in the OCS and for protection of the marine and coastal environments. The OCSLA requires preparing and maintaining a current five-year schedule of proposed lease auctions. NEPA requires preparation of an Environmental Impact Statement (EIS) before any major federal action. BOEM is the administrative agency responsible for leasing submerged federal lands and prepares an EIS before each Five-Year Program and subsequent lease sales.

BOEM evaluates the environmental impacts, including onshore socioeconomic impacts, of oil and gas activities in the OCS. Shortly after the passage of OCSLA, as amended, in 1978, BOEM (then MMS) began its efforts to model the implications of offshore development on onshore communities. Luton and Cluck (2000) tracks 15 years of data, methodology development, and analyses performed by the Environmental Studies Program from the first large-scale studies published in the mid-1980s. In the late 1990s, MMS's Developmental Benefits Model Assessment Team developed a consistent approach to regional economic modeling across OCS regions, and the first resulting OCS Economic Impact Model for the GOM was created soon thereafter. This model employed a two-stage, input-output framework to estimate employment, personal income, and similar economic impacts from OCS activities.

By 2005, MMS had developed the second generation of OCS Economic Impact Models, collectively named MAG-PLAN, which extended the consistent approach and incorporated both the GOM and Alaska OCS models into a single software framework (USDOI MMS 2005). MAG-PLAN's Stage 1 starts with BOEM estimates of the level of exploration, development, production, and infrastructure associated with a proposed OCS lease sale or set of sales (called an exploration and development, or E&D, scenario). The model allocates industry expenditures among IMPLAN industry sectors and then distributes the expenditure-by-sector spending to onshore areas. Stage 2 uses input-output multipliers from IMPLAN,[3] a commercial regional economic modeling program, to estimate employment, personal income, and other economic effects associated with different E&D scenarios by onshore area and type or impact.

This report is a continuation of BOEM's efforts to update, expand, and refine its socioeconomic impact analysis capabilities. Deepwater projects now generate the majority of oil production and about one-third of the gas production in the GOM OCS (USDOI MMS 2009).

[3] IMPLAN (IMpact Analysis for PLANning) is an input-output analysis (I-O) software package with modeling and data components. I-O is a means of examining relationships within an economy, both between businesses and between businesses and final consumers that captures all monetary market transactions for consumption in a given time period. The resulting mathematical formulae allow examination of the effects of a change in one or several economic activities on an entire economy (impact analysis). IMPLAN v.3 disaggregates the U.S. economy into 440 industry sectors and can be used to estimate change in employment (jobs), output, and earnings from increases or decreases in economic activity. IMPLAN industry sectors are consistent with NAICS codes; see http://implan.us/v3/index.php?option=com_docman&task=cat_view&gid=145&Itemid=138 for crosswalk tables.

The revised version of MAG-PLAN now has activity functions for FPSO vessels, subsea completions, and updated costs for other activity functions, as well as software upgrades.

2.2 Basic Concepts

2.2.1 Direct, Indirect, and Induced Effects

As mentioned previously, a goal of MAG-PLAN is to estimate the number of jobs, earnings, and economic output associated with oil and gas activities in the GOM OCS. MAG-PLAN Stage 1 tracks the "direct effects" (e.g., the number of jobs associated with drilling a well).

Stage II estimates the associated "indirect" and "induced" economic effects. Indirect effects are associated with the economic activities involved with backfilling a supply chain. For example, the steel pipe and cement consumed when a well is drilled create a demand to replenish these commodities, which, in turn, supports jobs in the steel and cement industries. "Induced effects" occur through household spending of the wages earned from drilling the well. The different types of effects structure MAG-PLAN's logic and calculations.

2.2.2 Activity Types/Activity Functions

The starting point for a BOEM socioeconomic analysis is an exploration and development (E&D) scenario developed by the BOEM Resource Evaluation Office, in which the Bureau estimates the oil-and-gas-related activities that could reasonably take place as a result of a proposed project, lease sale, or set of lease sales. A scenario describes activities that occur each year. These E&D activities, called activity types, are modeled in MAG-PLAN as activity functions. Table 1 cross-references the activity types in the E&D scenarios with the activity functions in MAG-PLAN.[4] The "cradle-to-grave" (from geological and geophysical prospecting to decommissioning) approach is characteristic of BOEM impact analyses.

As can be seen in Table 1, the activity types in an E&D scenario do not necessarily have a 1:1 correspondence to MAG-PLAN activity functions. For example, collecting seismic data to identify where to drill (i.e., geological and geophysical prospecting) might take place before a lease sale, before drilling an exploratory well, or after drilling an exploratory well if data collected while drilling the well (e.g., velocity) are used to process the G&G data properly (DeCort, personal communication, 2010).[5] Likewise, the type of production system added will depend, in part, on the water depth in which the system is located.

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[4] Readers familiar with the previous version of MAG-PLAN will note several changes in Table 1. The Exploratory Well Drilling activity type now maps to two activity functions: geological and geophysical prospecting and exploratory well drilling. Subsea Added and FPSO Added are new Activity Types to reflect the growth in the use of floating structures (e.g., spar, tension leg platform (TLP), mini-TLPs, semisubmersible systems) in addition to the more traditional caisson and fixed platform. Workover costs are now included within the annual O&M cost.

[5] Section 3.2 presents ERG's rationale for including G&G as part of the activity function for drilling exploratory wells in MAG-PLAN.

Table 1

Activity Function Codes and E&D Scenario Mapping

Activity Types in E&D Scenario	Activity Function in MAG-PLAN
Exploratory Well Drilled	Geological & Geophysical Prospecting
	Exploratory Well Drilling
Non-Productive Well Drilled	Non-Productive Well Drilling
Productive Well Drilled	Productive Well Drilling
Platform Added	Platform Fabrication and Installation
	Operating and Maintenance Costs
Subsea Added	Subsea completion(s)
	Operating and Maintenance Costs
FPSO Added	Floating Production, Storage, and Offloading
	Operating and Maintenance Costs
Gas Processing Facility– Offshore	Gas Processing Facility-Offshore
Gas Processing Facility– Onshore	Gas Processing Facility-Onshore
Gas Production	Gas Processing Operating and Maintenance Costs
Pipeline Miles Added	Pipeline Construction
Platform Removed – No Explosives	Platform Removed-No Explosives
Platform Removed – with Explosives	Platform Removed-With Explosives
Oil Spill – Reaching Shore[6]	Oil Spill-reaching shore
Oil Spill – Not Reaching Shore	Oil Spill-not reaching shore

Source: Updated from USDOI MMS (2005)

2.3 Activity Functions in MAG-PLAN

To run MAG-PLAN, the user must first use IMPLAN. The programs, then, are intertwined. Figure 1 illustrates this interrelationship. IMPLAN calculations and outputs are shown in the thick lines that surround and enter the center box that holds the MAG-PLAN calculations.

2.3.1 Prerequisite IMPLAN Analyses

The overall steps for running IMPLAN analyses prior to conducting a MAG-PLAN analysis are:

- Identify the geographic regions of interest
- Create an IMPLAN model for each region
- Create an IMPLAN analysis with a $1 million change in labor income
- Create a matrix of induced multipliers by region for labor expenditures
- Import into MAG-PLAN for use in Stage 2 calculations

[6] Rather than updating this function, which is not currently used, BOEM is exploring the possibility of estimating a broader range of employment effects, including job gains and lossesskm9me59 that may result from oil spills.

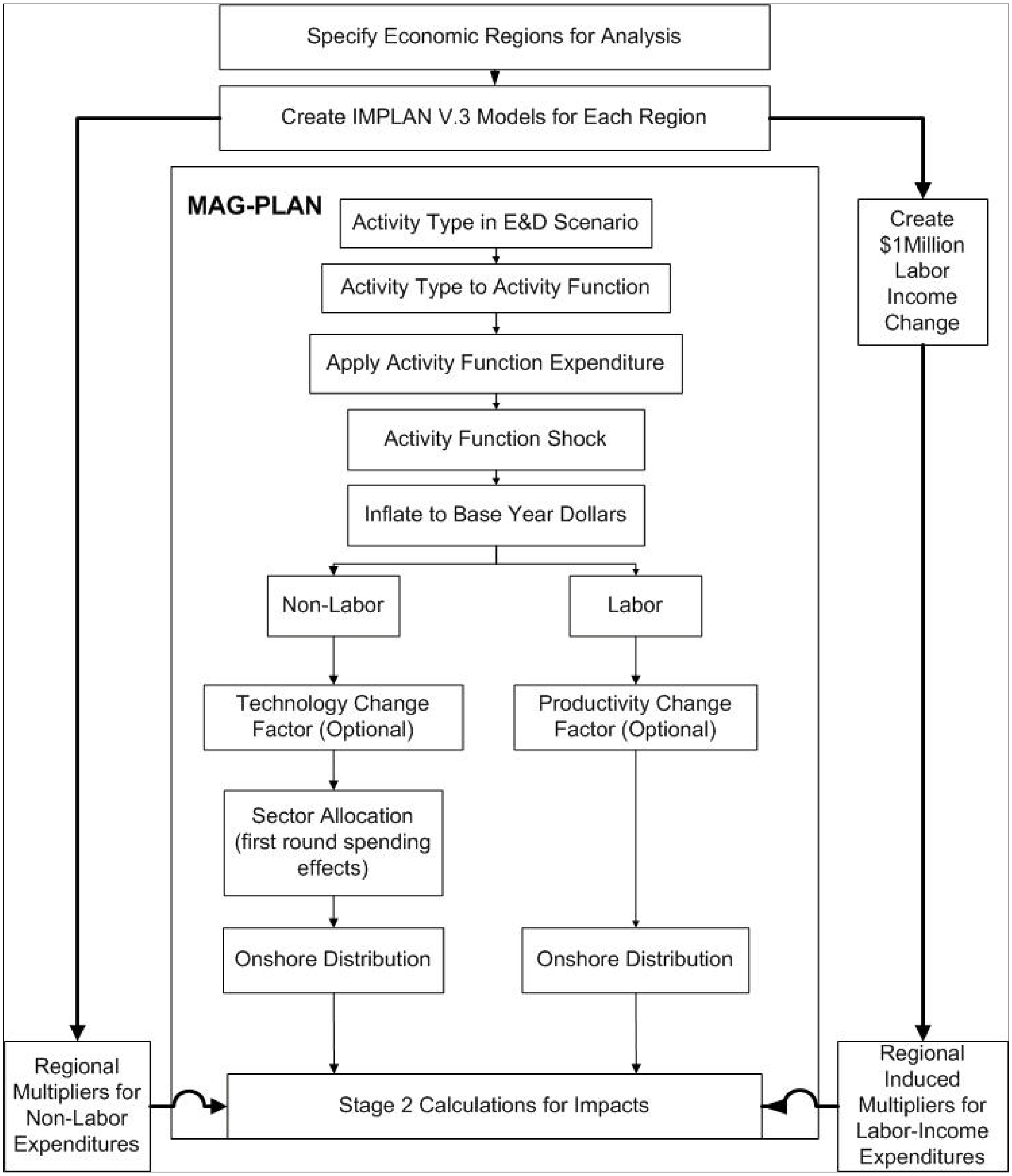

Figure 1. MAG-PLAN and IMPLAN interrelationship.

The IMPLAN model generates the direct, indirect, and induced multipliers for the non-labor expenditures by industry sector. Running the $1 million change in labor income to calculate the induced effect multipliers replaces the approach in MAG-PLAN 2005, which calculated disposable income, distributed the income among several income categories, and distributed the spending through the personal consumption expenditure matrix[7] to estimate spending by industry sector within Stage 1 (USDOI MMS 2005).

2.3.2 Setting up MAG-PLAN

Before analyzing an E&D scenario, the user must first define the MAG-PLAN Economic Regions to correspond to those in the IMPLAN Models. The regions must also have the same names as well as the same set of counties or parishes within them. The user will import an E&D scenario, select the offshore modeling area (e.g., Western GOM, Central GOM), designate the dollar base year for the analysis and select the start and end years, define or select the onshore areas to include in the analysis, and import the associated sets of IMPLAN multipliers for labor-income and non-labor expenditures for these onshore areas.[8]

2.3.3 Sample MAG-PLAN Calculation Flow

The logic flow within the white box in Figure 1 illustrates the calculations that take place when the model is executed for a given E&D scenario. BOEM develops an E&D scenario with counts of each activity type that take place in a given year, for example, 2 platforms are added in Year 5. MAG-PLAN maps activity types to activity functions (see Table 1, above). The expenditures associated with each activity function form the shock to the model. The purpose of Stage 1 is to process the initial shock (e.g., drill a development well, construct and install a production platform, etc.) into non-labor and labor expenditures suitable for using with IMPLAN multipliers for indirect and induced effects. Chapter 3.0 provides details on the estimated expenditure(s) associated with each activity function. Because all MAG-PLAN 2012 data are in terms of 2008$, the first step is to inflate the values to base year dollars for the analysis. The shock is then divided into non-labor and labor components.

2.3.3.1 Non-labor Expenditures

MAG-PLAN 2012 is configured with a "Technology Change Series" input class for non-labor expenditures to reflect a "learning curve" with new technology. (That is, the first of any new technology might be very expensive to build while, further up the learning curve, subsequent examples are less expensive.) Currently, the default value is for the Technology Factor is 1.0 (meaning there is no adjustment for changes in technology) but this can be changed by the user.

Next, non-labor expenditures are allocated among the 440 IMPLAN industry sectors based on the methodology in USDOI MMS (2005) pages 21 through 29. The Activity by Sector matrix represents the outcome of examining the top five sectors in the production function for an activity and re-distributing the original share of a sector among all the sectors that "feed" into its production function. The production function used by ICF to estimate the first-round effects is based on an IMPLAN model of 31 parishes in Southern Louisiana (USDOI MMS 2005). It is

[7] Spending patterns differ by income level.

[8] The user must also select or confirm the remaining input class selections. The default input class selections will normally be acceptable for most analyses.

this process that provides the basis for the statement in USDOI MMS (2005) that, in MAG-PLAN, direct effects also incorporate the first round spending effects. Sector allocations for geological and geophysical prospecting, FPSOs, and subsea systems are discussed in Chapter 3.0.

In MAG-PLAN 2012, non-labor expenditures by sector are distributed to onshore areas by one of two approaches. The first approach is an industry-specific onshore distribution built from the bottom up by examining company and facility data. ERG 2011 examined about 1,140 locations for 17 oil service industries.[9] For the MAG-PLAN 2012 update, these 17 distributions were combined into onshore distributions for 8 IMPLAN sectors. ERG also used the same approach to develop onshore distributions for the platform fabrication industry (IMPLAN sector 209 for shipbuilding and repairing), subsea completion component of the oil and gas field equipment and machinery (IMPLAN sector 206), and insurance carriers (IMPLAN industry 357). The second approach used IMPLAN's "regional purchase coefficients" (RPCs) as proxies to estimate the proportion of demand supplied from sources within the region ("regional shares" or RSs). This approach started at the largest scale (e.g., U.S. versus Rest of World), and worked through smaller and smaller scales until onshore distributions could be developed by industry for the economic impact areas within each of the five Gulf States (Texas, Louisiana, Mississippi, Alabama, and Florida) and the rest of each state. For the purpose of this report, the term "GOM economic area" refers to the five Gulf States while the term "GOM economic impact areas" refers to subsets of counties and parishes BOEM considered most likely to be impacted by oil and gas operations in the OCS. Chapter 5.0 presents the methodology for developing the onshore distributions. While these approaches provide some improvements to the 2005 distributions, they represent intermediate steps that will likely be refined in the future.

The end result is a matrix of expenditures by industry sector by onshore area. The sum of all the Stage 1 non-labor entries should equal the inflation-adjusted non-labor expenditure for the activity.

2.3.3.2 Labor Income Expenditures

As with the non-labor expenditures, MAG-PLAN is configured with a "Productivity Change Series" input class for labor income expenditures to address a situation where technological development results in an increase in labor productivity (see Figure 1). Labor income expenditures are distributed to onshore areas by activity function.

MAG-PLAN 2005 had a single onshore distribution based on the Labor Needs Survey (ICF 2008) for all labor expenditures. MAG-PLAN 2012 uses the same onshore distributions for labor income expenditures as for non-labor expenditures, except for the following activity functions:

- Exploratory drilling
- Development drilling
- Development drilling and completion
- Production operations and maintenance, including workovers.

[9] Geological and geophysical prospecting, contract drilling, drilling fluid supplies, drilling tools and supplies, mud logging, measurement while drilling (MWD), cementing, formation evaluation, completion, fishing, wellhead equipment suppliers, accommodations, air transport, water transport, catering, workovers, and diving support.

The onshore distribution based on the Labor Needs Survey is applied to these four activity functions, see Section 5.4 for details.

2.3.4 Stage 2 Calculations

Stage 2 is where the multiplication of 440 industry sectors by 8 IMPLAN multipliers by *n* regions takes place.[10] The results can be exported as .csv files, summarized into tables, or otherwise processed as needed for BOEM reports. The non-labor expenditures—allocated into industry sectors and distributed to onshore areas—are multiplied by the direct, indirect, and induced effect regional multipliers generated by the regional IMPLAN models. The labor income expenditures—distributed to onshore areas by activity function—are multiplied by the induced effect regional multipliers estimated by the $1 million change in labor income generated in the regional IMPLAN models. The multiplier represents the number of jobs created in each region by a $1 million change in labor income, and is a weighted average of the labor income multipliers for each of the 440 industry sectors for each region.

2.4 Revenue Functions in MAG-PLAN

BOEM collects funds from oil and gas operations in the OCS through:

- Bonus bids
- Rental payments
- Royalties on oil and gas production

A bonus is the cash consideration paid to the United States by the successful bidder for a mineral lease. Rental payments are paid (usually annually) on a lease from the time of the sale until oil and gas production begins on the lease or the lease expires, whichever comes first. Royalties are a percentage of the value of production from the lease.

OCSLA, as amended, requires that the federal government set aside 27 percent of the bonus, rental, and royalty income received from leases within 3 miles of the edge of state waters. The 3-mile band of federal waters is known as the "8(g) zone" after the section of the legislation that created the requirement. The BOEM Economics Division staff calculates the annual "8(g)" and "non-8(g)" revenues for an E&D scenario from which anticipated bonuses, rentals, and royalties are calculated; these form six separate columns in the E&D scenario spreadsheet. The onshore distribution and sector allocation for the revenue functions are discussed in Chapter 6.0.

[10] MAG-PLAN 2012 uses the aggregated multipliers for output, employment, total value added, labor income, proprietor income, employee compensation, indirect business tax, and other property type income. The previous version used the disaggregated multiplier matrices. BOEM determined that any change to a region's inter-industry relationships would be best made within IMPLAN rather than MAG-PLAN 2012. In addition, the change from an industry by industry by multiplier type matrix (i.e., 440 by 440 by 8) to an industry by multiplier type matrix (i.e., 440 by 8) leads to increased stability and faster processing time.

3.0 INDUSTRY EXPENDITURES

The base year for the MAG-PLAN update is 2008, based on the most recent IMPLAN data available at the time this effort was undertaken. All expenditures[11] are inflated/deflated to 2008$ using the Consumer Price Index (CPI-U) (USDOL BLS 2010) and are presented in units of thousands of dollars. MAG-PLAN output is inflated to the base year set by the user. All MAG-PLAN estimates are in base-year constant dollars.

ERG updated expenditures for:

- Wells (Section 3.1)
- Geological and geophysical prospecting (Section 3.2)
- Platform fabrication and installation, subsea systems, and floating systems (Section 3.3)
- Onshore gas processing facilities (Section 3.4)
- Offshore pipeline construction costs (Section 3.5)
- Platform decommissioning (Section 3.6)
- Production operations and maintenance (Section 3.7)
- Onshore gas processing operations and maintenance (Section 3.8)
- Pipeline operations and maintenance (Section 3.9)

ERG also developed the sector allocation for new activity functions (Section 3.10).

Note that operating and maintenance expenditures (Sections 3.8 and 3.9) are annual activities that occur each year for the lifetime of the capital asset with which they are associated.

ERG did not update the oil spill cleanup expenditures from those published in USDOI MMS (2005). Rather than updating this function, which is not currently used, BOEM is exploring the possibility of estimating a broader range of employment effects, including job gains and losses that may result from oil spills.

For some activities, the discussion of the data sources and estimation methods is detailed and complex.12 These discussions are included in appendices, while the findings are summarized in Chapter 3.

3.1. DRILLING AND ASSOCIATED GEOLOGICAL AND GEOPHYSICAL PROSPECTING

BOEM took the opportunity to coordinate the expenditure estimates for wells and platforms used in the models for resource evaluation and socioeconomic impact models. Section 3.1.1 discusses the initial expenditures for exploration wells, and Section 3.1.2 discusses the initial expenditures for nonproductive development wells. Section 3.1.3 d escribes the potential increases to drilling expenditures due to the interim final rule for increased safety measures published by BOEM (then known as BOEMRE) on October 14, 2010 (USDOI BOEMRE

[11] MAG-PLAN models industry expenditures, which in some cases may be slightly different than industry costs. However, for the purpose of this report the two terms are used interchangeably.

[12] Because we rely on published data for much of the population of MAG-PLAN variables, there is some inevitable mixture of onshore and offshore oil and gas activities in those data. (The NAICS does not distinguish between onshore and offshore regions.) Throughout this report, ERG has described the steps taken to identify offshore operations more closely. While the current model calculates reasonable projections for the socioeconomic impacts of oil and gas activities in the offshore region, the further specification of offshore operations would refine these projections.

2010a). Finally, the expenditures for completing and equipping productive development wells are discussed in Section 3.1.4. Section 3.1.5 is a summary of the expenditures included in MAGPLAN 2012.

3.1.1 Exploration Wells

The GOMR Office of Resource Evaluation (ORE) estimated well costs using three sources: (a) the offshore oil and gas supply module equations developed by the U.S. Department of Energy, Energy Information Administration as part of its National Energy Modeling System (NEMS) USDOI EIA (2010a), (b) FieldPlan Offshore Facility Evaluation software, and (c) internal cost databases maintained by ORE. Estimated well costs were modeled assuming an oil price of approximately $100/BO for the high case and $80/BO for the low case. The cost data were analyzed to create the hybrid; estimated exploratory well and productive development well range (high, mid, low) of well costs. Well depth is given in units of feet while water depth is given in units of meters (as in MAG-PLAN). ERG deflated the high cost estimates to 2008$ (see Table 2). The three-phase methodology was used in order to incorporate all available data and develop ranges of well costs that afford flexibility for MAG-PLAN input requirements.

Table 2

Initial Exploratory Well Costs

	Initial Exploratory Well Cost (2008$)		
	Well Depth (ft)		
Water Depth (m)	0 to 15,000	15,000 to 18,000	18,000+
0–60	$8,137,500	$18,066,667	$32,037,000
60–200	$18,709,500	$35,825,000	$48,885,667
200–400	$21,997,500	$42,478,250	$58,678,667
400–800	$26,336,000	$50,918,000	$70,360,000
800–1,600	$32,917,000	$64,682,500	$97,787,667
1,600–2,400	$40,381,500	$88,609,000	$143,590,333
2,400 +	$45,134,667	$103,967,000	$177,984,000

Source: USDOI BOEM (2011b), high cost estimates, deflated to 2008$.

ERG calculated "average" well costs by water depth for the Western and Central GOM planning areas based on the historical distribution of well depths by water depths seen in each planning area (see Table 3).[13] ERG then used the well distribution by water depth by OCS planning area (see Table 4) to develop an "average" initial well cost by water depth for the combined Western and Central GOM planning areas (see Table 5).

[13] The historical distribution of well depths may underestimate the depths of the projected wells in the E&D forecast because ORE's analysis of historical well depths in the GOM suggests that there is a positive correlation between time (years) and annual average well depth.

Table 3

Exploratory Well Distribution by Water Depth, Well Depth, and Planning Area

Water Depth (m)	Well Depth			Sum
	0 to 15,000	15,000 to 18,000	18,000+	
Western Gulf of Mexico				
0–60	78%	20%	2%	100%
60–200	92%	1%	7%	100%
200–400	79%	7%	14%	100%
400–800	79%	7%	14%	100%
800–1,600	62%	15%	23%	100%
1,600–2,400	48%	1%	51%	100%
2,400 +	92%	4%	4%	100%
Central Gulf of Mexico				
0–60	71%	18%	11%	100%
60–200	90%	7%	3%	100%
200–400	93%	3%	4%	100%
400–800	93%	3%	4%	100%
800–1,600	60%	10%	30%	100%
1,600–2,400	45%	16%	39%	100%
2,400 +	45%	15%	40%	100%

Source: USDOI BOEM (2011c).

Table 4

Exploratory Well Distribution between Planning Areas by Water Depth For Calculating Average Well Costs for Combined Western and Central GOM Planning Areas

Water Depth (m)	GOM Planning Area	
	Western	Central
0–60	18.7%	81.3%
60–200	24.7%	75.3%
200–400	28.4%	71.6%
400–800	28.4%	71.6%
800–1,600	30.7%	69.3%
1,600–2,400	8.8%	91.2%
2,400 +	24.7%	75.3%

Source: Calculated from well count data by planning area in USDOI BOEM (2011c).

Table 5

Intermediate Average Exploratory Well Cost (2008$) by Water Depth and Planning Area

	Planning Area		
Water Depth (m)	Western	Central	Western and Central
0–60	$10,601,323	$12,553,695	$12,188,601
60–200	$20,992,987	$20,812,870	$20,857,359
200–400	$28,566,516	$24,079,169	$25,353,576
400–800	$34,220,100	$28,834,420	$30,363,953
800–1,600	$52,602,078	$55,554,750	$54,648,280
1,600–2,400	$93,500,280	$88,349,345	$88,802,627
2,400 +	$52,801,933	$107,099,250	$93,687,813

Source: ERG estimates derived from data in Tables 2 through 4.

3.1.2 Nonproduction Development Wells

ERG used the same methodology as with exploration wells (see Section 3.1.1 a bove) to calculate average well costs for nonproduction development wells. The term refers to wells that differ from exploratory well costs because they have been drilled from a platform rather than a mobile offshore drilling unit or MODU. The development well costs provided by ORE do not contain completion costs for final activities after the casing has been run (such as swabbing) to put the well into production. Nor do the ORE cost estimates include lease equipment costs associated with production. The nonproduction well costs are representative of wells drilled to delineate the reservoir or for water injection. Table 6 is the initial set of development well costs provided by ORE and deflated to 2008$. Table 7 lists the distributions with which to calculate an average well cost by water depth and planning area, while Table 8 lists the distributions used in the calculation of a combined average Western and Central GOM planning area development well. Table 9 is the intermediate cost for a development well that is not put into production.

Table 6

Initial Development Well Costs

	Initial Development Well Cost (2008$)		
	Well Depth (ft)		
Water Depth (m)	0 to 15,000	15,000 to 18,000	18,000+
0–60	$6,095,500	$14,424,667	$27,985,500
60–200	$8,228,000	$18,347,000	$36,067,000
200–400	$9,629,250	$20,264,500	$38,673,667
400–800	$12,629,667	$25,803,000	$42,686,000
800–1,600	$17,738,500	$33,499,333	$49,615,000
1,600–2,400	$19,529,667	$39,007,333	$55,076,250
2,400 +	$22,224,167	$45,034,833	$61,404,500

Source: USDOI BOEM (2011b), high cost estimates, deflated to 2008$.

Table 7

Development Well Distribution by Water Depth, Well Depth, and Planning Area

Water Depth (m)	Well Depth 0 to 15,000	15,000 to 18,000	18,000+	Sum
Western Gulf of Mexico				
0–60	88%	10%	2%	100%
60–200	97%	1%	2%	100%
200–400	76%	4%	20%	100%
400–800	76%	4%	20%	100%
800–1,600	45%	40%	15%	100%
1,600–2,400	50%	5%	45%	100%
2,400 +	98%	1%	1%	100%
Central Gulf of Mexico				
0–60	88%	10%	2%	100%
60–200	93%	5%	2%	100%
200–400	95%	2%	3%	100%
400–800	95%	2%	3%	100%
800–1,600	60%	20%	20%	100%
1,600–2,400	55%	15%	30%	100%
2,400 +	60%	5%	35%	100%

Source: USDOI BOEM (2011c).

Table 8

Development Well Distribution by Water Depth and Planning Area For Calculating Average Well Costs for Combined Western and Central GOM Planning Areas

Water Depth (m)	GOM Planning Area Western	Central
0–60	9.7%	90.3%
60–200	15.5%	84.5%
200–400	13.4%	86.6%
400–800	13.4%	86.6%
800–1,600	18.2%	81.8%
1,600–2,400	13.6%	86.4%
2,400 +	52.5%	47.5%

Source: Calculated from well count data by planning area in USDOI BOEM (2011c).estimates.

Table 9

Intermediate Average Development Well Cost (2008$) by Water Depth and Planning Area

Water Depth (m)	Planning Area		
	Western	Central	Western and Central
0–60	$7,366,217	$7,366,217	$7,366,217
60–200	$8,885,970	$9,290,730	$9,227,992
200–400	$15,863,543	$10,713,288	$11,403,422
400–800	$19,167,867	$13,794,823	$14,514,811
800–1,600	$28,824,308	$27,265,967	$27,549,585
1,600–2,400	$36,499,513	$33,115,292	$33,575,546
2,400 +	$22,844,077	$37,077,817	$29,605,103

Source: ERG estimates derived from data in Tables 6 through 8.

3.1.3 Increased Costs Due to New Regulatory Requirements

BOEM (then known as BOEMRE) published an interim final rule on October 14, 2010, regarding increased safety measures for offshore oil and gas drilling operations (USDOI BOEMRE 2010a). The new requirements mean additional rig time and tests to be made during the drilling operations. Based on the benefit-cost analysis for the interim rule, the percentage increase to the well costs would be:

- 1.58 percent for all exploratory wells and for development wells drilled from MODUs
- 0.6 percent for development wells drilled from fixed platforms

(USDOI BOEMRE 2010b).

Because ERG assumes that production structures in water depths up to 200 m are fixed platforms, development wells drilled in water depths up to 200 m are increased by 0.6 percent. All other wells (that is, all exploratory wells plus development wells drilled in water depths greater than 200 m) are increased by 1.58 percent.

3.1.4 Productive Development Wells

To estimate the total expenditures for putting a development well into production, ERG added the expenditures to complete and equip the well to the expenditures presented in Sections 3.1.2 and 3.1.3. ERG estimated completion costs and lease equipment costs separately. Completion costs might vary by well depth because of the differing amounts of cement to seal the casing. The U.S. Department of Energy (USDOE) National Energy Technology Laboratory (NETL) developed a benchmarking report of deep well costs (USDOE NETL 2005) that contains very detailed costs as they might appear on an authorization for expenditure form. Well completion services are a line item and, for an offshore development well, they form approximately 3.1 percent of the total well costs.

The USDOE Energy Information Administration (EIA) publishes an annual report on oil and gas lease equipment and operating costs (USDOE EIA 2010a). The report presents data for onshore lease equipment costs but not for offshore operations. However, with the exception of transportation costs, the equipment costs for processing oil and gas will depend more on the volume of oil or gas that needs to be processed rather than whether the equipment is located above land or water. USDOE EIA (2010a) presents lease costs for oil production on the basis of a 10-well project. Table 10 summarizes the average lease equipment costs for oil production, while Table 11 summarizes the lease equipment costs for gas production. The equipment for oil production ranges from $142,000 per well to $381,000 per well. In contrast, equipment for gas production ranges from $36,000 for a small, shallow well to $176,000 for a deep well producing 10 MMcf/day.

Table 10

Lease Equipment Costs for Oil Production

Well Depth (ft)	Cost (2008$)	
	Project	Per-well
2,000	$1,417,700	$141,770
4,000	$1,917,100	$191,710
8,000	$2,808,800	$280,880
12,000	$3,808,600	$380,860
Average	$2,488,100	$248,810

Source: USDOE EIA (2010a)

Table 11

Lease Equipment Costs for Gas Production

Well Depth (ft)	Costs in 2008$ by Per-Well Gas Production Rate						
	50 Mcf/day	250 Mcf/day	500 Mcf/day	1 MMcf/day	5 MMcf/day	10 MMcf/day	Average
2,000	$35,800	$36,200					$36,000
4,000	$35,800	$55,400	$64,100				$51,800
8,000	$45,800	$86,800	$84,600	$118,300			$83,900
12,000		$109,900	$105,900	$118,000	$140,300		$118,500
16,000			$113,500	$118,300	$140,200	$175,800	$137,000
Average	$36,600	$66,700	$93,100	$118,100	$140,300	$175,800	

Source: USDOE EIA (2010a)

Because we do not know, a priori, whether a well will produce oil or gas, for the purpose of estimating costs, ERG uses the average oil production equipment cost of $248,800. That is, the expenditures on completion and equipment for a well are 3.1 percent of the well cost plus $248,800.

3.1.5 Final Well Costs in MAG-PLAN 2012

Tables 12 through 14 are the well costs in MAG-PLAN 2012; they are in thousands of 2008$. Exploratory wells have the 1.58 percent increase due to new regulatory costs. Development well costs are increased by 0.6 percent if drilled in water depths up to 200 m and by 1.58 percent if drilled in deeper waters to reflect increased regulatory costs. Productive development wells have the added completion and equipment costs described in Section 3.1.4.

Table 12

Estimated MAG-PLAN 2012 Exploratory Well Costs (Thousands, 2008$)

Water Depth (m)	Exploratory Well Cost (Thousands, 2008$)					
	Well Depth (ft)			Average		
	0 to 15,000	15,000 to 18,000	18,000+	Western	Central	Western & Central
0–60	$8,266	$18,352	$32,543	$10,769	$12,752	$12,381
60–200	$19,005	$36,391	$49,658	$20,993	$21,079	$20,857
200–400	$22,345	$43,149	$59,606	$28,567	$24,402	$25,354
400–800	$26,752	$51,723	$71,472	$34,220	$29,221	$30,364
800–1,600	$33,437	$65,704	$99,333	$52,602	$55,867	$54,648
1,600–2,400	$41,020	$90,009	$145,859	$93,500	$88,636	$88,803
2,400 +	$45,848	$105,610	$180,796	$52,802	$107,420	$93,688

Source: ERG estimates based on data in Table 5 and information in Section 3.1.3.

Table 13

Estimated MAG-PLAN 2012 Nonproductive Development Well Costs (Thousands, 2008$)

Water Depth (m)	Nonproductive Development Well Cost (Thousands, 2008$)					
	Well Depth (ft)			Average		
	0 to 15,000	15,000 to 18,000	18,000+	Western	Central	Western & Central
0–60	$6,132	$14,511	$28,153	$7,410	$7,410	$7,410
60–200	$8,277	$18,457	$36,283	$8,939	$9,346	$9,283
200–400	$9,781	$20,585	$39,285	$16,114	$10,883	$11,584
400–800	$12,829	$26,211	$43,360	$19,471	$14,013	$14,744
800–1,600	$18,019	$34,029	$50,399	$29,280	$27,697	$27,985
1,600–2,400	$19,838	$39,624	$55,946	$37,076	$33,639	$34,106
2,400 +	$22,575	$45,746	$62,375	$23,205	$37,664	$30,073

Source: ERG estimates based on data in Table 9 and information in Section 3.1.3.

Table 14

Estimated MAG-PLAN 2012 Productive Development Well Costs (Thousands, 2008$)

Water Depth (m)	Productive Development Well Cost (Thousands, 2008$)					
	Well Depth (ft)			Average		
	0 to 15,000	15,000 to 18,000	18,000+	Western	Central	Western & Central
0–60	$6,571	$15,210	$29,275	$7,889	$7,889	$7,889
60–200	$8,783	$19,278	$37,657	$9,465	$9,885	$9,820
200–400	$10,333	$21,472	$40,751	$16,863	$11,469	$12,191
400–800	$13,476	$27,272	$44,953	$20,323	$14,696	$15,450
800–1600	$18,826	$35,332	$52,210	$30,436	$28,804	$29,101
1,600–2,400	$20,702	$41,101	$57,930	$38,474	$34,930	$35,412
2,400 +	$23,524	$47,413	$64,557	$24,173	$39,080	$31,254

Source: ERG estimates based on data in Tables 9 and 10 and information in Section 3.1.3.

3.2 GEOLOGICAL & GEOPHYSICAL (G&G) PROSPECTING

G&G activities can occur at many phases in an offshore oil and gas operation—before a lease bid, before drilling an exploratory well, or after drilling an exploratory well if data collected while drilling the well (e.g., velocity) are used to process the G&G data properly (DeCort, 2010). For the purpose of including these costs in MAG-PLAN, ERG needs to be able to associate G&G expenses with the activities in E&D scenarios. Based on how the publicly available data are presented, ERG makes two modeling assumptions:

- All G&G costs are associated with exploratory wells
- Costs are incurred in the year prior to drilling the exploratory well

This approach has the effect of associating higher G&G costs with more expensive wells.

EIA collects financial data on major energy producers (USDOE EIA 2008). In completing the Form EIA-28 (financial reporting), companies with oil and gas activities file a Schedule 5211, which provides expense information by geographic region (USDOE EIA 2009a). In USDOE EIA (2008) Table T7, exploration costs are subdivided into:

- Acquisition of unproved acreage
- Geological and geophysical
- Drilling and equipping
- Other

Development costs are subdivided into:

- Acquisition of proved acreage
- Lease equipment
- Drilling and equipping
- Other

G&G expenses are reported only under exploration activities. This supports ERG's decision to assign G&G costs only to exploratory wells.

Table 15 is derived from the Schedule 5211 submissions (USDOE EIA 2009a). "Other" costs include direct overhead costs associated with exploration, carrying costs of undeveloped properties (lease rents); test hole contributions; and land development, leasing, and scouting (USDOE EIA 2009b).

From Table 15, we see that G&G costs range from a low of 15 percent of exploration drilling costs in 2006 to a high of 31 percent in 2003. The data for 2003 are likely to include the costs for Encana's well in the Beaufort Sea, but this is the only Alaskan well we could identify between 2000 and 2007 (USDOI MMS 2006). However, because the G&G-to-drilling cost percentage for 2003 lies within the range shown for the other years, we do not expect the inclusion of an Alaskan well to substantially change the average value of 21 percent. Thus, ERG estimated G&G costs as 21 percent of the exploratory well drilling cost (see Table 16).

Table 15

G&G Costs as a Percentage of Exploratory Drilling Costs ($millions)

	Year								
Parameter	2000	2001	2002	2003	2004	2005	2006	2007	Average
G&G	$573	$466	$466	$394	$607	$616	$590	$664	
Drilling and Equipment	$2,004	$2,169	$1,781	$1,804	$1,320	$2,163	$3,402	$2,458	
Other	$340	$340	$421	$398	$661	$726	$654	$831	
G&G as a Percentage of Drilling Costs	24%	19%	21%	18%	31%	21%	15%	20%	21%

Source: USDOE EIA 2009a

Table 16

G&G Per-Well Costs in MAG-PLAN 2012

	G&G Costs (Thousands, 2008$)					
	Well Depth (ft)			Average		
Water Depth (m)	0 to 15,000	15,000 to 18,000	18,000+	Western	Central	Western & Central
0–60	$1,736	$3,854	$6,834	$2,261	$2,678	$2,600
60–200	$3,991	$7,642	$10,428	$4,409	$4,427	$4,380
200–400	$4,692	$9,061	$12,517	$5,999	$5,125	$5,324
400–800	$5,618	$10,862	$15,009	$7,186	$6,136	$6,376
800–1,600	$7,022	$13,798	$20,860	$11,046	$11,732	$11,476
1,600–2,400	$8,614	$18,902	$30,630	$19,635	$18,614	$18,649
2,400 +	$9,628	$22,178	$37,967	$11,088	$22,558	$19,674

Source: ERG estimates based on data in Tables 12 and 15.

3.3 PRODUCTION SYSTEM FABRICATION AND INSTALLATION

BOEM resource evaluation engineers and socioeconomic analysts held multiple meetings to identify and include all costs while avoiding any overlaps between any pair of activity function costs. After resolving the detailed cost components needed within the estimates, BOEM engineers provided:

- Production structure costs, including the structure, production equipment, and infield flow lines. The production structures vary by water depth. For 0 to 60 m water depths, separate costs were developed for caissons, well protectors, and traditional fixed platforms. For 60 to 200 m water depths, the costs represented fixed platforms and spars. For all water depths beyond 200 m, the production systems are presumed to be floating structures (e.g. spar, semisubmersible, tension leg platform). The costs are the mean values for the distributions examined by the resource evaluation engineers.
- Subsea costs, which include the mean values for subsea flowlines, umbilicals, manifolds, risers, and other equipment, as well as any additional costs needed on the platform/production system to which the subsea system is connected.

Table 17 shows the costs in 2010$ and 2008$ and the conversion to thousands of dollars. At this time, MAG-PLAN 2012 is structured for a single cost for each water depth. ERG took a 60:40 weighted average of platform to caisson or well protector costs for systems in 0 to 60 m water depth based on the historical ratios of these production systems at that depth range. For subsea systems, ERG calculated a simple average of the three costs (Strellec 2011).

Table 17

Production System Costs

Data source	Subgroup (m)	Representative Structure	Production Facility Structure (Millions, 2010$)	Production Facility Subsea (Millions, 2010$)	2008$ (Millions)	MAG-PLAN 2012 (Thousands, 2008$)
Costs From BOEM GOMR ORE (2010$)	0–60	Fixed platform	$7.899		$7.822	
	0–60	Caisson or well protector	$2.687		$2.661	$5,758
	60–200	Fixed platform or spar	$17.271		$17.102	$17,102
	200–400	Floating	$100.003		$99.024	$99,024
	400–800	Floating	$180.591		$178.823	$178,823
	800–1,600	Floating	$364.454		$360.887	$360,887
	1,600–2,400	Floating	$571.271		$565.679	$565,679
	2,400+	Floating	$593.475		$587.666	$587,666
	800–1,600	Subsea development		$158.326	$156.78	
	1,600–2,400	Subsea development		$187.593	$185.76	
	2,400+	Subsea development		$216.860	$214.74	$185,757
	200-800	Floating				$138,924

Source: USDOI BOEM, 2011b.

3.4 ONSHORE GAS PROCESSING FACILITY

ERG examined the semiannual worldwide construction survey published by the *Oil & Gas Journal* from November 2006 through December 2010 (Kootungal 2006; 2007a,b; 2008a,b; 2009a,b; and 2010a,b). ERG extracted the data for new gas processing plants in the United States for which the estimated cost was published. The date of the survey in which the project is first mentioned is the nominal year for the cost data. Table 18 lists the eight onshore gas processing projects identified through this search. The absence of projects in 2009 is understandable in light of the economic crisis that occurred in October 2008. ERG chose to include all of the projects listed, resulting in an overall average of $92.80 million (2008$) for new onshore gas processing projects.

Table 18

New Onshore Gas Processing Projects 2006–2010

Company	Location	Capacity (MMcf/d)	Year	Cost (Nominal, millions)	Cost (Millions, 2008$)	Source
Energy Transfer Partners LP	Johnson County, TX	115	2006	$65	$69.42	Kootungal 2006
CDM MAX LLC	Cameron Parish, LA	600	2007	$15	$15.57	Kootungal 2007a
Devon Energy	Calvin, OK		2007	$30	$31.14	Kootungal 2007b
Hiland Partners	Woodford Shale, OK	40	2007	$23	$23.87	Kootungal 2007b
PVR Mistream	Bethany Field, TX	80	2007	$20	$20.76	Kootungal 2007b
Enogex	Clinton, OK	120	2008	$55	$55.00	Kootungal 2008b
Dominion Energy	Pleasants County, WV	10	2010	$253	$249.96	Kootungal 2010b
Occidental	Elk Hills oil and gas field, CA	200	2010	$280	$276.64	Kootungal 2010b
Average					$92.80	

3.5 PIPELINE CONSTRUCTION

US DOE EIA maintains a Natural Gas Pipeline Project database (Gaul 2009; USDOE EIA 2010b) and supplied a copy of the database for this project. ERG identified 12 natural gas pipeline projects that were completed since 2005 in the offshore GOM planning areas that had an in-service year, cost in million dollars, and pipeline miles. ERG used several approaches to find water depth data for each project. Some water depths are taken from project descriptions. For others, ERG identified the OCS block in which the production structure was located and then found the water depth in that block. Not all water depth categories were represented in the data. ERG assumed a linear relationship between water depth and cost and performed a regression analysis on the data. The resulting equation was used to estimate the cost per mile for each depth category.

Table 19 presents the estimated costs while Appendix A contains the data and detailed discussions. The costs range from $1,760,000 per mile for a pipeline in 0 to 60 m water depth to $2,380,000 per mile for a pipeline in water depths at or exceeding 2,400 m. MAG-PLAN 2012 is currently structured for a single pipeline construction cost; thus, ERG uses the midpoint value of $2,070,000 per mile.

Table 19

Estimated Cost per Mile by Water Depth (Thousands, 2008$)

Water Depth Range (m)	Water Depth Midpoint (m)	Cost Per Mile (Thousands, 2008$)
0–60	30	$1,760
60–200	130	$1,780
200–400	300	$1,810
400–800	600	$1,880
800–1,600	1,200	$2,000
1,600–2,400	2,000	$2,170
2,400+	3,000	$2,380
All depths		$2,070

Source: ERG estimates

3.6 PLATFORM DECOMMISSIONING

On October 15, 2010, BOEM (then known as BOEMRE) issued a Notice to Lessees and Operators (NTL) with guidance on decommissioning wells and structures (USDOI BOEMRE 2010c). In particular, the definition of when decommissioning takes place changes from one year after a lease terminates (i.e., a lease basis) to when a well or platform stops production for five years or more (i.e., a well and structure basis).

ERG used two recent publications to estimate decommissioning costs. Kaiser et al. (2009a,b) provides information on actual decommissioning costs for platforms in the GOM from 2003 to 2008 in water depths ranging from 0 to approximately 90+ m (300+ ft). Proserv Offshore (2009) provides engineering estimates, based on representative platforms and structures in water depths ranging from 400 to 8,000 feet (approximately 120 m to over 2,400 m). This latter report also focused strictly on GOM structures.

Based on these reports, ERG estimated decommissioning costs for fixed platforms, spars, TLPs and mini-TLPs, and semisubmersibles. Appendix B contains the specific assumptions made for each structure type and water depth.

The findings are presented in Table 20. Note that decommissioning with explosives is less expensive than decommissioning without explosives; however, decommissioning costs with explosives were available only for water depths up to 200 meters. The most expensive types of structures to decommission are those in water depths ranging from 200 to 800 meters (e.g., TLPs, mini-TLPs, spars, fixed platforms). Floating production structures, such as semisubmersibles, are two to three times less expensive to decommission.

Table 20

Cost of Platform/Structure Decommissioning in the GOM by Water Depth (Thousands, 2008$)

Water Depth			With	Without
Meters	Feet	Assumed Type (a)	Explosives	Explosives
0–60	0–200	Fixed Platform	$1,528	$1,757
60–200	200–650	Fixed Platform	$4,445	$5,111
200–400	650–1,300	Fixed Platform	NA	$40,525
400–800	1,300–2,600	Mini-TLP/Spar/Fixed Platform	NA	$45,198
800–1,600	2,600–5,200	Semisubmersible/TLP/Spar	NA	$25,133
1,600–2,400	5,200–8,000	Semisubmersible/Spar	NA	$24,973
2,400+	8000+	Semisubmersible	NA	$16,692

(a) In 400 to 800 m depths, 33 percent are assumed spars, 33 percent are assumed mini-TLPs, and 33 percent are assumed fixed platforms, represented by one platform at 400 m. In 800 to 1,600 m depths, 4 percent are assumed semisubmersibles, 46 percent are assumed spars, 33 percent are assumed TLPs, and 17 percent are assumed mini-TLPs. In 1,600 to 2,400 m depths, 44 percent are assumed spars and 56 percent are assumed semisubmersibles (based on information collected by Proserv Offshore 2009).

Source: Kaiser et al. 2009a,b; Proserv Offshore 2009.

3.7 PRODUCTION O&M

In MAG-PLAN 2012, annual production O&M costs are calculated on a p er-production system basis beginning with the year the system is installed and continuing for 15 years.[14] These costs were generated by BOEM, GOMR ORE in order to be consistent with the data used to estimate the well and production structure costs (see Section 3.1.1 above for more details). Table 21 presents the average costs in 2010$ and 2008$. A user can chose between average costs or high costs for wells and production costs in an E&D scenario but cannot mix cost types (e.g., high well costs with average production costs) within a run without specifically editing a cost file to reflect this.

Table 21

Average and High O&M Cost Per Production System by Water Depth (Thousands, 2008$)

		Average		High	
Water Depth (m)	Representative System	Annual Operating Cost (Thousands, 2010$)	Annual Operating Cost (Thousands, 2008$)	Annual Operating Cost (Thousands, 2010$)	Annual Operating Cost (Thousands, 2008$)
0–60	Caisson, well protector, or platform	$979.0	$969.0	$1,668.9	$1,653.0
60–200	Fixed platform or spar	$979.0	$969.0	$1,668.9	$1,653.0
200–400	Floater	$4,290.8	$4,249.0	$12,006.9	$11,889.0
400–800	Floater	$4,290.8	$4,249.0	$12,006.9	$11,889.0
800–1,600	Floater	$10,652.2	$10,548.0	$43,267.5	$42,844.0
1,600–2,400	Floater	$10,652.2	$10,548.0	$43,267.5	$42,844.0
2,400+	Floater	$10,652.2	$10,548.0	$43,267.5	$42,844.0
	Subsea development	$4,290.8	$4,249.0	$12,006.9	$11,889.0
200–800	Floater	$4,290.8	$4,249.0	$12,006.9	$11,889.0

Source: USDOI BOEM, 2011b

[14] The previous version of MAG-PLAN used a per-well basis for production O&M costs.

3.8 ONSHORE GAS PROCESSING O&M

ERG had difficulty identifying O&M costs for onshore gas processing facilities. Many of them are part of large, integrated companies and, although financial data for the companies might be publicly available, even the segment data is too consolidated to use for this purpose. In recent years, there has been a growth in "midstream" companies that focus on the gathering, processing, and transport of natural gas and natural gas liquids. Many of these companies, such as WTG Gas Processing, are private, and financial data are not available.

Targa Resources Partners, L.P. meets the criteria of being a publicly traded company that has a segment in natural gas gathering and processing (Targa Resources Partners LP 2009). Table 22 lists the operating costs and volumes processed for 2009, 2008, and 2007. The cost to process a Bcf ranges from $315,800 in 2009 to $359,700 in 2008, with 2007 costs falling within this range. MAG-PLAN 2010 uses the 2008 value of $359,700 Bcf for onshore gas processing O&M costs.

Table 22

Estimated Onshore Gas Processing O&M Costs

	Year			
Parameter	2009	2008	2007	Source (page)
Operating Expenses (Millions)	$51.4	$55.3	$50.9	70
Volume of Gas Processed (MMcf/Day)	445.9	421.2	429.3	70
Convert to Bcf/year	162.8	153.7	156.7	
Convert to $/Bcf	$315,815	$359,703	$324,836	
MAG-PLAN 2010 (Thousands/Bcf, 2008$)		$359.7		

Source: Targa Resources Partners LP 2009

3.9 PIPELINE OPERATIONS AND MAINTENANCE

The *Oil & Gas Journal* (OGJ) printed a special report on pipelines in September 2009 with fiscal year 2008 data. The detailed tables listed the gas volumes transported for others in MMcf as well as the O&M costs. ERG cross-referenced the company names in the OGJ tables against those in BOEM's company list (USDOI BOEMRE 2010d) to identify companies with offshore operations in the GOM. Table 23 summarizes the data. The average annual O&M cost by volume transported is $28,000 per MMcf or $28,000,000 per Bcf.[15] This value is used for all water depths because the data are presented on a company basis, that is, aggregated over all pipeline depths operated by the company.

[15] USDOI MMS 2005 lists units of $/mile on pages xix and 5, and $/Bcf/year in Table 2-9 on p. 15. The values in Table 2-9 are more likely to be in thousands of dollars per Bcf per year. These range from $59,000 to $87,000. That is, the revised estimates are about three to five times higher.

Table 23 Offshore Pipeline Operating Costs (2008$)

Company	Volumes MMcf	O&M expense (Thousands)	O&M Cost Thousands/MMcf
Algonquin Gas Transmission LLC	351,104	$77,998	$0.222
Alliance Pipeline LP	640,863	$66,315	$0.103
ANR Pipeline Co.	1,982,666	$292,042	$0.147
Black Marlin Pipeline Co.	516	$2,020	$3.915
Chandeleur Pipe Line Co.	29,554	$3,007	$0.102
Columbia Gulf Transmission Co.	993,349	$58,643	$0.059
Dauphin Island Gathering Partners	59,670	$8,030	$0.135
Desting Pipeline Co. LLC	284,717	$20,178	$0.071
Discovery Gas Transmission LLC	257,070	$5,384	$0.021
Dominion Transmission Inc.	620,055	$392,254	$0.633
El Paso Natural Gas Co.	1,740,860	$223,714	$0.129
Enbridge Offshore Pipelines (UTOS) LLC	47,311	$4,403	$0.093
Enbridge Pipelines (MidLa) LLC	36,241	$4,113	$0.113
Florida Gas Transmission Co. LLC	785,975	$93,532	$0.119
Garden Banks Gas Pipeline LLC	58,234	$3,916	$0.067
Gulf South Pipeline Co. LP	1,048,042	$148,122	$0.141
Gulf Stream Natural Gas System LLC	297,821	$18,269	$0.061
High Island Offshore Systems LLC	108,286	$25,074	$0.232
Mississippi Canyon Gas Pipeline LLC	160,453	$3,351	$0.021
Natural Gas Pipeline Co. of America	1,925,335	$599,021	$0.311
Nautilus Pipeline Co. LLC	63,049	$5,991	$0.095
Northern Natural Gas Co.	1,143,582	$260,722	$0.228
Panhandle Eastern Pipe Line Co. LP	701,616	$161,150	$0.230
Panther Interstate Pipeline Energy LLC	4,034	$890	$0.221
Sabine Pipe Line LLC	250,187	$13,480	$0.054
Sea Robin Pipeline Co. LLC	126,293	$14,297	$0.113
Southern Natural Gas Co.	879,172	$184,947	$0.210
Tennessee Gas Pipeline Co.	1,801,283	$412,888	$0.229
Texas Eastern Transmission LP	1,432,742	$397,165	$0.277
Texas Gas Transmission LLC	867,664	$105,696	$0.122
Transcontinental Gas Pipe Line Co. LLC	2,577,642	$542,623	$0.211
Trunkline Gas Co. LLC	643,316	$69,052	$0.107
Venice Gathering System LLC	22,560	$10,449	$0.463
Average			$0.280

Source: OGJ 2009

3.10 Sector Allocation For New Activity Functions

ERG assumes that G&G prospecting falls entirely (100 percent) within IMPLAN sector 369 (architectural, engineering and related services) and that subsea systems fall entirely within IMPLAN sector 206 (Mining and oil and gas field machinery).

ERG allocated an FPSO to two IMPLAN sectors: 209 (Shipbuilding and repairing) (90.48 percent) and 206 (Mining and oil and gas field machinery) (9.52 percent), based on the assumed FPSO activity function consisting of the vessel plus subsea system. A typical cost for a FPSO vessel is $1.9 billion and that of a subsea system is $200 million (see Appendix C for details).

4.0 LABOR COST PERCENTAGES

As explained in Chapter 2.0, the activity costs are split into labor and non-labor categories. Labor dollars go to households, where they are spent both within and outside of the region. Activity costs are presented in Chapter 3.0. Chapter 4.0 examines the percent of total activity costs formed by labor.

For activity functions where we have sufficient data, ERG developed composite labor shares that are aggregates of the different commodities and services that make up the activity. This was possible for drilling exploratory, nonproductive, and productive wells, as well as production O&M costs (see Section 4.1).

For the remaining activities, ERG identified the most appropriate NAICS code for each activity and downloaded 2007 Economic Census data from the U.S. Bureau of the Census for that code. The ratio of payroll to total revenues is the estimate of the labor share. These activities are discussed in Section 4.2. Section 4.3 contains some observations on how the labor share estimates for drilling wells compares with the values in earlier studies.

4.1 Activity Functions with Composite Labor Shares

4.1.1 Exploratory Well Drilling

The derivation of the labor share for wells is based on ERG (2011), which examined the role of service industries in offshore oil and gas activities in the GOM (see Table 24). The report took detailed cost data for “typical” deep offshore exploratory and development wells published in USDOE NETL (2005), grouped entries into service industries and commodities, and reconfigured them into IMPLAN sectors. No labor percentage is assigned to the commodity costs, and 100 percent was assigned to the company and contract labor line items.

The “percent” column in Table 24 lists the percentage of total costs by each service industry and commodity that contributes to drilling an exploratory well based on the data in USDOE NETL (2005). The next three columns are the revenues, payroll, and ratio of payroll-to-revenues based on the 2007 Economic Census (U.S. Census Bureau 2011). The ratio of payroll revenues provides the estimated initial labor share for that industry. The labor share for the industry is multiplied by the percentage of well costs represented by the industry to calculate the adjusted labor share. The rest of the cost for that industry goes to the IMPLAN sector as a non-labor expenditure.

When summed, the adjusted labor percentages result in a weighted average estimate of the household income from exploratory drilling operations. In Table 24, for every dollar spent in an exploratory drilling activity, 19.91 cents go to households and 80.09 cents are distributed among the 14 IMPLAN sectors. So as not to overstate the precision of the estimate, ERG assigned 20 percent as the labor share for drilling an exploratory well.

Table 24

Derivation of Labor Share for Exploratory Drilling

Sector Name	NAICS	Percent	Census Data (Million$) Revenues	Census Data (Million$) Payroll	Initial Labor Share	Adjusted Labor Share	Percent to IMPLAN Sector
Drilling Oil and Gas Wells	213111	42.88%	$22,201	$5,888	26.5%	11.37%	31.51%
Support Activities for Oil and Gas Operations	213112	11.37%	$45,754	$12,374	27.0%	3.08%	8.30%
Architectural and Engineering Services	541300	1.25%	$254,201	$97,560	38.4%	0.48%	0.77%
Air Transportation	481000	1.12%	$146,459	$26,438	18.1%	0.20%	0.92%
Water Transportation	483000	6.67%	$34,271	$4,041	11.8%	0.79%	5.88%
Truck Transportation	484000	0.85%	$217,895	$57,346	26.3%	0.22%	0.63%
Other Accommodations	721A00	0.35%	$180,308	$46,043	25.5%	0.09%	0.26%
Oil and Gas Field Equipment and Machinery	333132	3.74%	$16,504	$2,495	15.1%	0.56%	3.17%
COMMODITY EXPENDITURES (NO LABOR) *							
Iron and Steel Mills	331111	11.00%					11.00%
Cement Manufacturing	327310	2.78%					2.78%
Gasoline Stations	447000	2.65%					2.65%
Water, Sewage, and Other Systems	221300	0.14%					0.14%
Power Generation and Supply	221100	0.18%					0.18%
Insurance Carriers	524100	11.92 %					11.92%
Wages		3.12%			100.0%	3.12%	
Total		100.00%				19.91%	80.09%

*This is not to say there is no labor associated with the commodities, however, these jobs would not be directly associated with the labor located in the GOM for the drilling activities. It is the latter which we are estimating in this table. The jobs associated with commodities would appear as the indirect effect jobs for drilling.

Sources: ERG 2011; U.S. Census Bureau 2011; USDOE NETL 2005

4.1.2 Nonproductive Development Well Drilling

Table 25 repeats the calculations, but with the cost percentage profile for a nonproductive development well. For every dollar spent in drilling an offshore development well, 24.24 cents go to households and 75.76 cents are distributed among 14 other IMPLAN sectors. ERG assigned 24 percent as the labor share for drilling a nonproductive development well.

Table 25

Derivation of Labor Share for Nonproductive Development Drilling

Sector Name	NAICS	Percent	Census Data (Million$) Revenues	Census Data (Million$) Payroll	Initial Labor Share	Adjusted Labor Share	Percent to IMPLAN Sector
Drilling Oil and Gas Wells	213111	34.48%	$22,201	$5,888	26.5%	9.14%	25.34%
Support Activities for Oil and Gas Operations	213112	21.97%	$45,754	$12,374	27.0%	5.94%	16.03%
Architectural and Engineering Services	541300	1.86%	$254,201	$97,560	38.4%	0.72%	1.15%
Air Transportation	481000	0.91%	$146,459	$26,438	18.1%	0.16%	0.75%
Water Transportation	483000	7.58%	$34,271	$4,041	11.8%	0.89%	6.69%
Truck Transportation	484000	0.84%	$217,895	$57,346	26.3%	0.22%	0.62%
Other Accommodations	721A00	0.52%	$180,308	$46,043	25.5%	0.13%	0.39%
Oil and Gas Field Equipment and Machinery	333132	9.78%	$16,504	$2,495	15.1%	1.48%	8.30%
COMMODITY EXPENDITURES (NO LABOR)*							
Iron and Steel Mills	331111	10.27%					10.27%
Cement Manufacturing	327310	2.52%					2.52%
Gasoline Stations	447000	2.19%					2.19%
Water, Sewage, and Other Systems	221300	0.11%					0.11%
Power Generation and Supply	221100	0.16%					0.16%
Insurance Carriers	524100	1.26%					1.26%
Wages		5.55%			100.0%	5.55%	
Total		100.00%				24.24%	75.76%

*This is not to say there is no labor associated with the commodities, however, these jobs would not be directly associated with the labor located in the GOM for the drilling activities. It is the latter which we are estimating in this table. The jobs associated with commodities would appear as the indirect effect jobs for drilling.

Sources: ERG 2011; U.S. Census Bureau 2011; USDOE NETL 2005

4.1.3 Productive Development Well Drilling

The difference between a nonproductive well and a productive well is that the latter includes completion and lease equipment costs. ERG assigns these costs to NAICS 333132—oil and gas field equipment and machinery. For most well depth/water depth combinations, completion and equipment costs typically add about 4 percent to the cost of a nonproductive well (see Section 3.1.4).

Table 26 adds 4 percent to the oil and gas field equipment and machinery sector for a total of 13.8 percent of costs for a productive development well. The percentages for the other services and commodities are reduced proportionately so that the percentages sum to 100. For every dollar spent in drilling a productive offshore development well, 23.84 cents go to households and 76.16 cents are distributed among 14 other IMPLAN sectors. ERG uses 24 percent as the labor share for drilling a productive development well.

Table 26

Derivation of Labor Share for Productive Development Drilling

Sector Name	NAICS	Percent	Census Data (Million$) Revenues	Census Data (Million$) Payroll	Initial Labor Share	Adjusted Labor Share	Percent to IMPLAN Sector
Drilling Oil and Gas Wells	213111	32.95%	$22,201	$5,888	26.5%	8.74%	24.21%
Support Activities for Oil and Gas Operations	213112	21.00%	$45,754	$12,374	27.0%	5.68%	15.32%
Architectural and Engineering Services	541300	1.78%	$254,201	$97,560	38.4%	0.68%	1.10%
Air Transportation	481000	0.87%	$146,459	$26,438	18.1%	0.16%	0.72%
Water Transportation	483000	7.25%	$34,271	$4,041	11.8%	0.85%	6.39%
Truck Transportation	484000	0.80%	$217,895	$57,346	26.3%	0.21%	0.59%
Other Accommodations	721A00	0.49%	$180,308	$46,043	25.5%	0.13%	0.37%
Oil and Gas Field Equipment and Machinery	333132	13.78%	$16,504	$2,495	15.1%	2.08%	11.69%
COMMODITY EXPENDITURES (NO LABOR)*							
Iron and Steel Mills	331111	9.82%					9.82%
Cement Manufacturing	327310	2.41%					2.41%
Gasoline Stations	447000	2.09%					2.09%
Water, Sewage, and Other Systems	221300	0.10%					0.10%
Power Generation and Supply	221100	0.15%					0.15%
Insurance Carriers	524100	1.20%					1.20%
Wages		5.30%			100.0%	5.30%	
Total		100.00%				23.84%	76.16%

*This is not to say there is no labor associated with the commodities, however, these jobs would not be directly associated with the labor located in the GOM for the drilling activities. It is the latter which we are estimating in this table. The jobs associated with commodities would appear as the indirect effect jobs for drilling.

Sources: ERG 2011; U.S. Census Bureau 2011; USDOE NETL 2005

4.1.4 Comparison of Labor Share Estimates for Well Drilling

ERG found no data to support varying the percentage by well depth and water depth. Table 27 compares the values from this report, the 2005 model documentation, and Dismukes et al. 2003 (as reported in USDOI MMS 2005).

Table 27

Comparison of Labor Percentages for Drilling Wells

Source	Labor Percentages		
	Exploratory	Nonproductive Development	Development
This report	20%	24%	24%
USDOI MMS 2005	35%–40%	22%–27%	20%–27%
Dismukes et al. 2003	<10%	<10%	<10%

The estimates derived for this report are twice as large as those in Dismukes et al. 2003 for all well types. For productive and nonproductive development wells, the new estimates are in the middle of the range estimated in the previous model documentation (USDOI MMS 2005). The largest difference is for exploratory wells. The new estimate has the labor share being smaller for an exploratory well than a development well, while previously it was the converse. There was a steep cost increase in well drilling between 2002 and 2008 (see API 2008 and 2010). The increase could be due to a variety of factors, such as increased interest in drilling in deep and ultra-deep water areas, or advanced technologies (horizontal drilling, measurement while drilling, or other technologies to gather information about the formation). Labor costs might form a much smaller percentage of the additional costs for these technologically advanced methods. That is, it might be much more expensive to drill the well, but without a comparable increase in the amount of manpower to do it.

4.1.5 Production O&M

The USDOE EIA report, *Oil and Gas Lease Equipment and Operating Costs 1994–2009,* presents costs for fixed platforms in the GOM at 100-ft depth, 300-ft depth, and 600-ft depth and for two sizes: a 12-slot and an 18-slot platform (USDOE EIA 2010a). Table 28 arranges the data to compare cost components that vary with water depth, while Table 29 arranges the data to compare cost components that vary with the number of well slots.

4.1.5.1 Costs That Vary By Water Depth

Table 28 indicates that the following variables are unaffected by water depth for a given platform size:

- Labor
- Supervision
- Payroll Overhead
- Food Expense

Labor transportation costs vary by water depth because the latter is approximately related to distance from shore. There is a 3 percent increase in transportation costs in moving from the 100-ft depth to 300-ft depth but only an additional 1 percent increase to move from the 300-ft depth to the 600-ft depth.[16]

[16] Notes on distance assumptions: a review of water depths off the coasts of Louisiana and Texas indicates that water depths increase gradually out to about 50 nautical miles from shore (closer in eastern Louisiana and Texas waters), at which point depths quickly go from 100 m to greater than 400 m as the edge of the continental shelf is reached. Therefore, transportation costs from shore to 200–400 m water depths should not rise substantially from that seen in the 100–200 m water depth range.

Table 28

Cost Comparison by Water Depth

2008 Costs	12-slot			18-slot				Ratio of 300 ft to 100 ft costs		Ratio of 600 ft to 300 ft costs
	0–60 m (100 ft)	60–200 m (300 ft)	No Change	0–60 m (100 ft)	60–200 m (300 ft)	60–200 m (600 ft)	No Change	12-slot	18-slot	18-slot
Labor	$1,171,600	$1,171,600	*	$1,291,400	$1,291,400	$1,291,400	*			
Supervision	$175,700	$175,700	*	$193,700	$193,700	$193,700	*			
Payroll Overhead.	$538,900	$538,900	*	$594,000	$594,000	$594,000	*			
Food Expense	$122,600	$122,600	*	$140,200	$140,200	$140,200	*			
Labor Transportation	$3,045,300	$3,142,000		$3,045,300	$3,142,000	$3,175,200		1.03	1.03	1.01
Surface Equipment	$201,400	$201,400	*	$201,400	$201,400	$229,700				1.14
Operating Supplies	$40,300	$40,300	*	$40,300	$40,300	$45,900				1.14
Workover	$2,502,100	$2,620,200		$3,753,200	$3,930,300	$4,003,300		1.05	1.05	1.02
Communications	$57,800	$59,000		$77,000	$77,800	$78,200		1.02	1.01	1.01
Administrative	$565,300	$565,300	*	$613,200	$613,200	$626,800				1.02
Insurance	$412,400	$464,800		$605,000	$645,400	$1,037,400		1.13	1.07	1.61
Total	$8,833,400	$9,101,800		$10,554,700	$10,869,700	$11,415,800				

Source: USDOE EIA 2010a

Table 29

Cost Comparison by Number of Well Slots

2008 Costs	Water Depth					
	0–60 m (100 ft)			60–200m (300 ft)		
	12-slot	18-slot	Change	12-slot	18-slot	Change
Labor	$1,171,600	$1,291,400	1.10	$1,171,600	$1,291,400	1.10
Supervision	$175,700	$193,700	1.10	$175,700	$193,700	1.10
Payroll Overhead	$538,900	$594,000	1.10	$538,900	$594,000	1.10
Food Expense	$122,600	$140,200	1.14	$122,600	$140,200	1.14
Labor Transportation	$3,045,300	$3,045,300		$3,142,000	$3,142,000	
Surface Equipment	$201,400	$201,400		$201,400	$201,400	
Operating Supplies	$40,300	$40,300		$40,300	$40,300	
Workover	$2,502,100	$3,753,200	1.50	$2,620,200	$3,930,300	1.50
Communications	$57,800	$77,000	1.33	$59,000	$77,800	1.32
Administrative	$565,300	$613,200	1.08	$565,300	$613,200	1.08
Insurance	$412,400	$605,000	1.47	$464,800	$645,400	1.39
Total	$8,833,400	$10,554,700		$9,101,800	$10,869,700	

Source: USDOE EIA 2010a

Surface equipment costs do not change for water depths≤ 300 ft, but a 14 percent increase is seen when moving from 300-ft to 600-ft water depths. **Workover** costs increase by 5 percent between the 100-ft and 300-ft water depths and by only an additional 2 percent from the 300-ft depth to the 600-ft depth. **Communications** change minimally (i.e., an increase by 1 to 2 percent depending on the number of platforms and water depth). **Administrative** costs do not change for water depths ≤ 300 ft, but a 2 percent increase is seen when moving from 300-ft to 600-ft water depths.

Insurance costs increase with water depth. For a 12-slot platform, insurance costs increase by 13 percent between the 100-ft and 300-ft water depths. For an 18-well platform, insurance costs increase by 7 percent between the 100-ft and 300-ft water depths, so there appears to be some economies of scale when the platform is located in water depths of 300 feet or less. When an 18-slot platform moves from 300-ft to 600-ft water depths, however, insurance costs increase by 61 percent—the largest change seen in any of the parameters.

4.1.5.2 Costs That Vary by the Number of Well Slots

Table 29 holds the water depths constant but varies the number of well slots. As anticipated there is no change in the costs for labor transportation, but there is also no change in the costs for surface equipment, or operating supplies.

We see some economies of scale in the data in Table 29 as the number of well slots increases from 12 to 18 (i.e., a 50 percent increase). Only workover costs show a comparable 50 percent increase when the number of well slots increases from 12 to 18. Labor, supervision, and payroll overhead increase by only 10 percent, while administrative costs increase by 8 percent. Food expenses increase by 14 percent.[17] Communication costs increase by about a third, and insurance increases between 39 and 47 percent.

4.1.5.3 O&M Costs by Labor and Non-Labor Components

ERG interpolated the EIA Cost Study Report data to estimate O&M costs for a four-well structure in 0 to 60 m water depth, 6-slot structures in 60 m and 200 m water depths, and a 12-well structure at 200 to 400m water depth and examined the percentage of the costs formed by labor expenses (see Table 30). Labor share is the sum of labor, supervisory, and administrative costs. Administrative costs are assumed to represent the onshore labor costs that support the offshore operations. Payroll overhead is not included in labor share because it is not available for the employees to spend.

Table 30

Production O&M Costs

2008 Cost Items	0–60 m 4 Slots	60–200 m 6 Slots	60–200 m 6 Slots	200–400 m 12 Slots
Labor Share	25.4%	22.3%	21.4%	19.5%
Payroll Overhead	7.1%	6.2%	5.9%	5.5%
Food Expense	1.5%	1.4%	1.4%	1.2%
Labor Transportation	46.4%	40.1%	38.6%	31.7%
Surface Equipment	3.1%	2.6%	2.8%	2.6%
Operating Supplies	0.6%	0.5%	0.6%	0.5%
Workover	12.7%	22.3%	22.3%	26.6%
Communications	0.5%	0.6%	0.6%	0.6%
Insurance	2.8%	4.0%	6.5%	11.9%
Total	100.0%	100.0%	100.0%	100.0%

Source: ERG estimates.

The largest change is the increase in the cost of insurance, which grows from 2.8 percent in the 0–60 m water depth category to nearly 12 percent for a structure in 200–400 m water depth. The percentage nearly doubles as the water depth goes from 60–200 m to 200–400 m. At 400 m, operations have left the shelf and are moving down the slope to the deepwater regions. The pattern of insurance costs is consistent with increased risks with deeper waters. The jump in insurance costs as a percentage of overall costs results in all but one cost item showing relative decreases with increasing water depth. The exception is workover costs that increase monotonically but not necessarily proportionately with the number of wells.

[17] Perhaps due to the need for another person on the kitchen staff to serve the additional crew members.

USDOE EIA (2010a) does not provide operating cost data for deeper waters. As a result, ERG had no basis for extrapolating how the proportion of cost items changed for depths greater than 400 m. In effect, we assume that the proportions stay the same while the absolute value of the O&M costs increases in the slope and deepwater regions. Production O&M, therefore, is the only activity for which ERG can develop labor shares that differ by water depth. Labor shares are 25 percent, 22 percent, and 20 percent for 0–60 m, 60–200 m, and >200 m water depths, respectively.

4.2 LABOR SHARES FOR REMAINING ACTIVITIES

For the remaining activities, ERG identified the most appropriate NAICS code for each activity and downloaded 2007 Economic Census national data from the U.S. Bureau of the Census for that code (Table 31). The ratio of payroll to revenues is the estimated labor share. The exception is offshore pipeline O&M, where we used the state data for Louisiana.[18]

Table 31

Labor Shares by Activity

Activity	Water Depth (m)	Closest NAICS	Census Data (Million$)		Labor Share
			Revenues	Payroll	
Exploratory Drilling	all	composite			20%
Nonproductive Development Drilling	all	composite			24%
Development Drilling and Production	all	composite			24%
G&G Prospecting	all	541360	$3,093	$791	26%
Platform Fabrication and Installation	all	336611	$17,234	$4,618	27%
FPSO	all	336611	$17,234	$4,618	27%
Subseabed	all	333132	$16,504	$2,495	15%
Onshore Gas Processing Construction	all	237120	$30,295	$8,947	30%
Offshore Pipeline Construction	all	237120	$30,295	$8,947	30%
Decommission Platform (explosives)	all	238910	$85,524	$19,119	22%
Decommission Platform (no explosives)	all	238910	$85,524	$19,119	22%
Onshore Oil Spill	all	562910	$12,632	$3,512	28%
Offshore Oil Spill	all	562910	$12,632	$3,512	28%
Production O&M	0–60	composite			25%
	60–200	composite			22%
	200–400	composite			20%
	400–800	composite			20%
	800–1,600	composite			20%
	1,600–2,400	composite			20%
	2,400+	composite			20%
Onshore Gas Processing O&M	all	211112	$42,363	$501	1%
Offshore Pipeline O&M (LA)	all	486210	$1,283	$114	9%

Source: U.S. Census Bureau 2011

18 The labor share for Texas was very close to the national average of 16 percent; hence, ERG considered the Texas data to be more representative of onshore pipelines than offshore pipelines.

5.0 ONSHORE DISTRIBUTIONS

As was discussed in Chapter 2.0, the first stage of MAG-PLAN takes the money that is spent by oil and gas operations on activities in the GOM OCS region and:

- Calculates the spending into activities
- Divides the spending from activities into IMPLAN industry sectors
- In effect, identifies where the spending would come onshore by industry sector

The result is a matrix of spending by industry by user-defined onshore geographical region, or economic impact area (EIA). The Stage 1 output becomes the Stage 2 input, where the direct, indirect, and induced jobs and output supported by that spending are estimated through the use of IMPLAN multipliers.

MAG-PLAN v2 (USDOI MMS 2005) was structured to evaluate impacts on three Texas EIAs, four Louisiana EIAs, four Florida EIAs, one Alabama EIA, one Mississippi EIA, one "Other GOM" EIA that contained all the counties and parishes not included in the EIA already defined, and an "Other U.S." region for the remaining 45 states and the District of Columbia. One of the enhancements to MAG-PLAN 2012 is the ability to define new geographic areas of interest (or EIAs) within the model based on new research on the relationships between counties and parishes. This enhancement necessitates the development of a methodology to distribute the spending in the GOM OCS to geographic areas as small as an individual county or parish as well as to the rest of the world. MAG-PLAN 2012, for example, splits the "Other GOM EIA" into five EIAs–Rest of Texas, Rest of Louisiana, Rest of Mississippi, Rest of Alabama, and Rest of Florida—that contain the counties and parishes not in the EIAs already defined.

In other words, to complete the third bullet listed above, a 440 by n matrix (440 industry sectors by n geographic areas) was developed, where the row totals sum to 100 percent.

A combination of two approaches is used to estimate the onshore distribution of spending on activities in the GOM OCS region: a "top down" approach and a "bottom up" approach, geographically speaking (i.e., from larger to smaller geographic units or vice versa). These approaches are used 1) to provide information that IMPLAN is not designed to provide (using the top-down approach) or 2) to tailor the distributions of certain industries of particular importance to offshore oil and gas operations (using the bottom-up approach).

For the top-down approach, ERG uses IMPLAN's "regional purchase coefficients" (RPCs) as proxies to estimate the proportion of demand supplied from sources within the region. This simplification does not include all the trading considerations that IMPLAN calculates for a "regional share" or (RS). The RS is used in a binary decision calculation—demand that is not supplied by a region must be supplied from outside the region and can be calculated as (1-RS) for any region.

The direct use of IMPLAN RPCs does not work to answer all the questions regarding where GOM OCS dollars are spent within certain regions, particularly the most important immediate area bordering the GOM. IMPLAN provides the user with the internal demand for a region, which is supplied within the region, but not the proportion of demand for the entire region met by any subset of the region. For example, if an IMPLAN model calculates the RS for the five-state GOM region (comprising Texas, Louisiana, Mississippi, Alabama, and Florida), it does not provide the portion of the five-state supply that is contributed by Texas, for example.

Alternatively, an IMPLAN model for the state of Texas calculates the RS of the state's demand provided by the state's supply, but this approach also cannot provide Texas' supply contribution relative to the five-state supply. An approach was developed to calculate a weighted average contribution from each state to the five-state supply that uses the RSs from all five of the state IMPLAN models as well as RSs from the five-state region model to address this situation. Section 5.2 walks the reader through the top-down calculations.

The bottom-up approach addresses the issues inherent in a national model (e.g. IMPLAN). Because IMPLAN is a national model, its underlying data reflect all operations in the nation. However, there are certain industries for which a national model cannot adequately represent spending patterns in the offshore GOM OCS region. For example, IMPLAN Sector 209 is shipbuilding. There are major shipbuilding facilities on the East and West Coasts as well as in the GOM. However, fixed platforms and parts of floating production systems will be manufactured in the GOM, not on the East or West Coasts. Thus, the top-down approach is not appropriate for this sector. To tailor the analysis for offshore oil and gas operations in the GOM region, a bottom-up approach to tailor the onshore distributions of certain sectors important to offshore oil and gas operations is used. For specific industries, a detailed analysis of the businesses and locations offering these services and commodities (ERG 2011) was expanded for the industry sectors considered as part of this study. See Section 5.3 for details.

Section 5.1 discusses in detail the different areas considered within MAG-PLAN v3. Section 5.2 addresses the top-down approach for apportioning GOM OCS spending to the key areas of interest. Section 5.3 summarizes the bottom-up approach and presents how the detailed onshore distributions were derived and the sectors for which they were developed. Section 5.4 discusses the different onshore distributions used for labor spending. Methods to modify the Gulf-wide matrix to reflect the Western and Central GOM planning areas are discussed in Section 5.5.

5.1 ONSHORE AREAS OF INTEREST

Figure 2 is the first in a series of conceptual illustrations of the onshore geographic areas of interest. The circle defines the border between the United States and the Rest of World (ROW). The combined area inside of the circle represents the amount of domestic demand that is provided by domestic supply. The area outside of the largest circle represents the amount of domestic demand met by imports.

In Figure 3, the inner circle represents the five-state GOM region of Texas, Louisiana, Mississippi, Alabama, and Florida. The space between the inner circle and the outer circle represents the Rest of the United States.

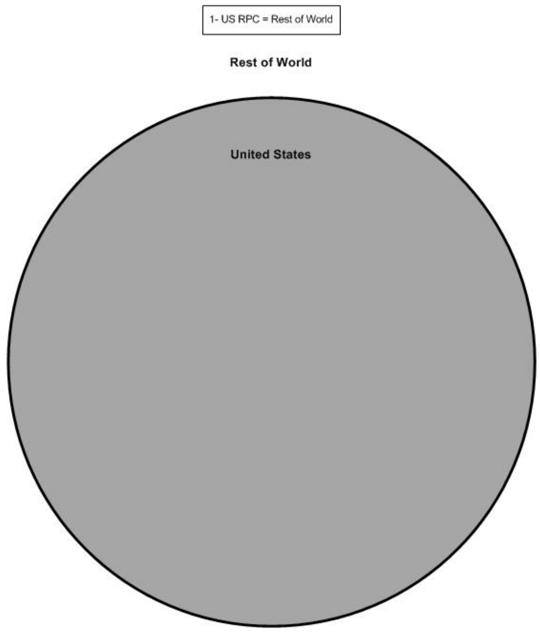

Figure 2. United States and the ROW

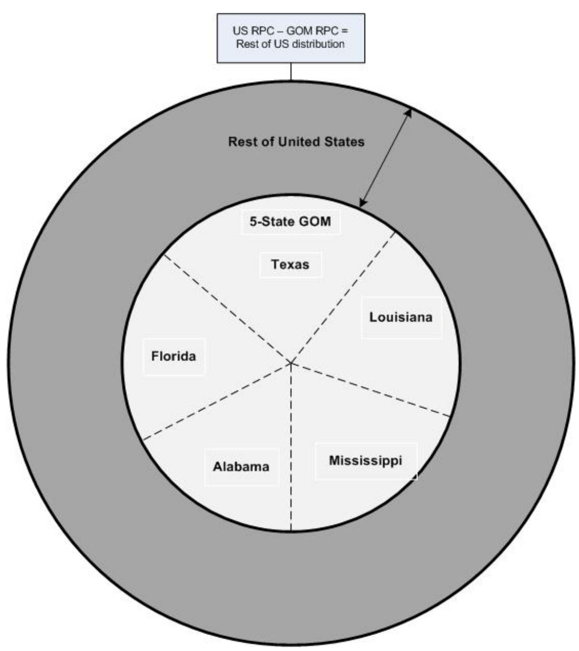

Figure 3. Five-State GOM Region and the Rest of the United States

In Figure 4, the five-state GOM region is the larger circle, while the green inner circle represents the subset of individual counties and parishes within the five states that are the likeliest to be affected by spending on activities in the offshore GOM ("Gulf coast economic impact area"). In MAG-PLAN v3, this subset of counties and parishes can be joined into regions or BOEM-defined economic impact areas (EIAs). The space between the GOM counties and the rest of the state is the "Rest of [State]" region. In Figure 4, the Texas GOM counties are represented by the green wedge between the dotted lines indicating the boundaries between Florida, Texas, and Louisiana. The Rest of Texas is the gray area indicated by the double-headed arrow.

Figure 4. GOM counties and parishes, rest of state regions within the five-state GOM Region.

Figure 5 is the composite summary of the different regions considered within MAG-PLAN 2012.

Tables 32 through 35 list the 189 counties and parishes that can be included and grouped into economic impact areas (EIAs). The only constraint is that each EIA must lie within a single state. In this section, for simplicity, the set of 189 counties and parishes is called the "Gulf coast economic impact area." That is, the "Five-State GOM" refers to the entirety of the five states (i.e., both the green and light gray regions in Figure 5), while the "Gulf coast economic impact area" refers to 189 counties and parishes that can be included and grouped in to BOEM-defined EIAs (i.e., only the green region in Figure 5). In addition to the BOEM-defined EIAs, results can be reported for the Rest of State for each of the 5 GOM states, Rest of U.S., and Rest of World.

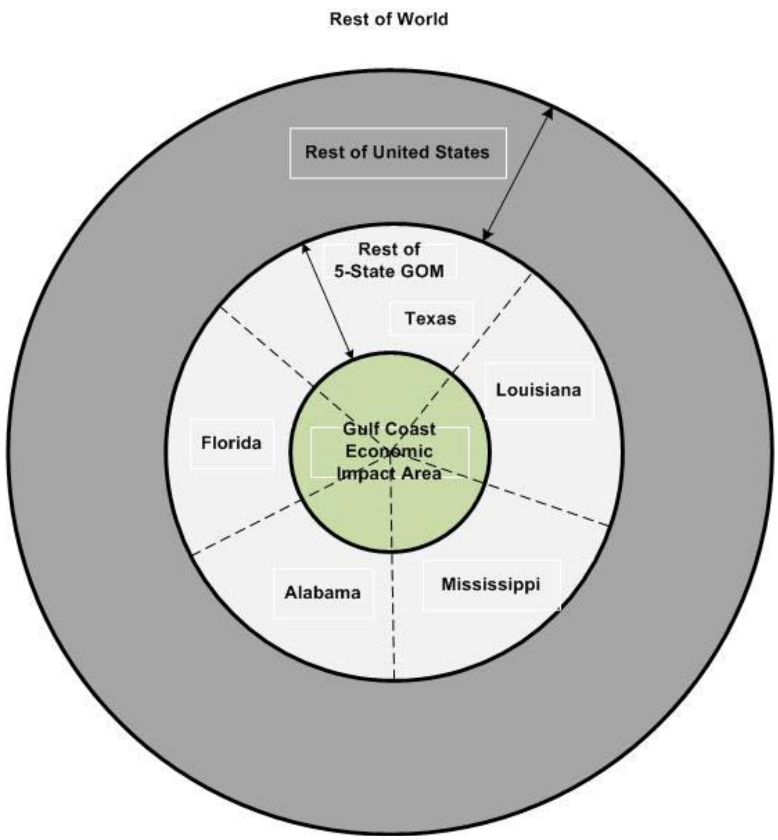

Figure 5. MAG-PLAN 2012 geographic regions of interest.

Table 32

Texas: 63 Counties That Can Be Included in the Gulf Coast Economic Impact Area

Angelina	Colorado	Jackson	Matagorda	Trinity
Aransas	Dewitt	Jasper	McMullen	Tyler
Austin	Duval	Jefferson (TX)	Montgomery	Victoria
Bastrop	Fayette	Jim Hogg	Newton	Walker
Bee	Fort Bend	Jim Wells	Nueces	Waller
Brazoria	Galveston	Karnes	Orange	Washington
Brazos	Goliad	Kenedy	Polk	Webb
Brooks	Gonzales	Kleberg	Refugio	Wharton
Burleson	Grimes	La Salle	Sabine	Willacy
Caldwell	Guadalupe	Lavaca	San Augustine	Wilson
Calhoun	Hardin	Lee	San Jacinto	Zapata
Cameron (TX)	Harris	Liberty	San Patricio	
Chambers	Hidalgo	Live Oak	Starr	

Source: USDOI MMS (2005) and Fannin et al. (2011).

Table 33

Louisiana: 40 Parishes That Can Be Included in the Gulf Coast Economic Impact Area

Acadia	East Baton Rouge	Lafourche	St. Bernard	St. Tammany
Allen	East Feliciana	Livingston	St. Charles	Tangipahoa
Ascension	Evangeline	Natchitoches	St. Helena	Terrebonne
Assumption	Iberia	Orleans	St. James	Vermilion
Avoyelles	Iberville	Plaquemines	St. John the Baptist	Vernon
Beauregard	Jefferson (LA)	Pointe Coupee	St. Landry	Washington
Calcasieu	Jefferson Davis	Rapides	St. Martin	West Baton Rouge
Cameron (LA)	Lafayette	Sabine	St. Mary	West Feliciana

Source: USDOI MMS (2005) and Fannin et al. (2011).

Table 34

Mississippi and Alabama Counties that Can Be Included in the Gulf Coast Economic Impact Area

15 Mississippi Counties		17 Alabama Counties	
Amite	Marion	Baldwin	Houston
Forrest	Pearl River	Butler	Lowndes
George	Perry	Choctaw	Marengo
Greene	Pike	Clarke	Mobile
Hancock	Stone	Conecuh	Monroe
Harrison	Walthall	Covington	Perry
Jackson	Wilkinson	Dallas	Washington
Lamar		Escambia	Wilcox
		Geneva	

Source: USDOI MMS (2005) and Fannin et al. (2011).

Table 35

Florida: 54 Counties that can be included in the Gulf Coast Economic Impact Area

Alachua	DeSoto	Hernando	Liberty	Putnam
Baker	Dixie	Highlands	Madison	Santa Rosa
Bay	Escambia	Hillsborough	Manatee	Sarasota
Bradford	Franklin	Holmes	Marion	Sumter
Broward	Gasden	Jackson	Miami-Dade	Suwannee
Calhoun	Gilchrist	Jefferson	Monroe	Taylor
Charlotte	Glades	Lafayette	Okaloosa	Union
Citrus	Gulf	Lake	Palm Beach	Wakulla
Clay	Hamilton	Lee	Pasco	Walton
Collier	Hardee	Leon	Pinellas	Washington
Columbia	Hendry	Levy	Polk	

Source: ERG estimates

5.2 TOP-DOWN APPROACH

A goal of developing an onshore distribution of expenditures in the offshore GOM is to be able to evaluate the jobs, output, and other economic measures that reflect the local and regional spending patterns (as reflected in IMPLAN multipliers). To evaluate the effects of those expenditures, we need to estimate the portion of spending that occurs within the region for each IMPLAN sector. The end product to be used in MAG-PLAN is a 440-industry by 196-region[19] matrix where the rows are the industries, the columns are the region, and cell content represents the percentage of expenditures that occur in that region for that industry. (Note that each row sums to 100 percent.)

ERG created IMPLAN models for the nation; five-state GOM; and individual states of Texas, Louisiana, Mississippi, Alabama, Florida; plus an additional five models where each one contains the counties or parishes within a state that are in the Gulf coast economic impact area (that is, the counties and parishes listed in Tables 32 through 35). In the top-down approach, we start with the largest region (World) and make a series of RS comparisons with increasingly smaller regions until we reach the state subregions shown in green in Figures 4 and 5, which contain the 189 counties and parishes listed in Tables 32 through 35. Table 36 summarizes the regions and comparisons.

5.2.1 The Rest of World

Returning to Figures 2 and 5, the outermost circle is the dividing line between the proportion of national demand addressed by domestic production and that supplied by imports from the ROW. The portion of spending per industry that leaves the United States is calculated as:

ROW onshore $\text{distribution}_i = 1 - \textit{U.S. National } RS_i$

Where:

RS = Regional share based on the regional purchase coefficient
i = IMPLAN industry sectory

That is, what the United States does not produce for itself is what the ROW supplies.

[19] Comprised of 189 counties or parishes, 5 Rest of State, 1 Rest of US, and 1 Rest of World.

Table 36

Overview of Top-Down Approach

Region 1	Region 2	Compare to Estimate	Described in Section
World	U.S.	Rest of World	5.2.1
U.S.	Five-State GOM	Rest of United States	5.2.2
Five-State GOM	TX, LA, MS, AL, FL	Partition the five-state GOM region among the five individual states	5.2.3
TX	TX-GOM	Partition each state into “GOM” and “Rest of State” regions	5.2.4
LA	LA-GOM		
MS	MS-GOM		
AL	AL-GOM		
FL	FL-GOM		
		Partition each state “GOM” region into individual counties and parishes	5.2.5

5.2.2 Rest of United States

The difference between the percentage of demand supplied internally by the five-state GOM region and the percentage that must be supplied by the rest of the nation is represented by the area between the outer and middle circles (In Figures 3 and 5, see the double-headed arrow pointing right in the light gray area). The proportion of spending per industry that leaves the five-state GOM region but stays within the United States is calculated as:

$$\textit{Rest of U.S. onshore distribution}_i = \textit{U.S. National } RS_i - \textit{Five-state GOM region } RS_i$$

Where:

RS = Regional share based on the regional purchase coefficient

i = IMPLAN industry sector

5.2.3 Texas, Louisiana, Mississippi, Alabama, and Florida

In Figures 4 and 5, the reader will notice that the area within the middle circle (i.e., light gray and green) is subdivided into states by the dotted lines. At this point, we need to divide the five-state GOM region into individual states. As mentioned at the beginning of the chapter, an IMPLAN model does not tell you the portion of demand in a larger region (e.g., five-state GOM) that is supplied by a smaller subregion (e.g., Texas). Furthermore, we cannot simply assign one-fifth of the five-state GOM RS to each state because each state will have its own pattern of being able to supply its own demand for each industry. This pattern has as its basis the relative level of production for a specific industry in each state (that is, for a particular industry, some states produce more of a commodity than others and thus, can contribute a greater supply to the larger region). Therefore, we need a method for distributing supply that reflects what each state could contribute to the local production in the five-state GOM region in each industry sector.

ERG uses coal as an example of how this relationship is estimated by combining the information within each state’s RS and that of the larger five-state GOM region (the gray plus green areas in Figure 5). In the example, the five-state GOM region RS for coal is 27.19 percent; that is, for every 100 units of coal demanded, 27.19 units are internally supplied by the five states. Table 37 illustrates the calculations for allocating the 27.19 units among the five states. The first line uses each state's RS to represent the number of units supplied within the state for every 100 units demanded with the state. In the example, Texas has an RS of 11.47 percent for coal. For every 100 units of coal demanded in Texas, then, 11.47 units are supplied locally. Alabama has an RS of 46.91 percent for coal, while Florida has an RS of less than 1 percent for coal. That is, the range of the proportion of coal supplied to meet local demand reflects the differing resource bases for coal among this group of states. The five-state sum is 70.28 units supplied locally within the five-state region. This number of units, though, cannot be compared to demand. A percentage comparing this supply (70.28 units) to the amount demanded cannot be directly calculated using this number, which, by itself, is meaningless. It can, however, be used to provide a sense of the underlying ability of each state to meet the overall demand of the five-state region.

The second line in Table 37 addresses the question, "Of all the coal supplied in the five-state region, what proportion is supplied by each state?" Alabama, for example, produces 46.91 units of every 70.28 units of coal (or 66.75 percent of the 70.28 coal units supplied within the five-state region). Finally, the third line answers the question, "How can we assign a number of units supplied by each state per 100 units demanded within the five-state region such that the sum of those units will match the 27.19 units supplied with the five-state region?" The table, now reporting percentages rather than units in the third line, reflects a weighted average RS for each of the states, which is obtained by multiplying the percentage of supply provided by a state shown in the second line by the five-state RS (27.19 percent). For Alabama, then, the state's share is 27.19 units (or percent) times 66.75 percent, which yields a weighted RS of 18.15 percent. In this way, the sum of the individual state RPs is set equal to 27.19 percent (i.e., the five-state RP)—the amount of demand supplied by internal sources—but each state's portion now reflects what that state could contribute to the supply, given its coal resources.

Table 37

Sample Calculation to Apportion Five-State RS among Five States

	TX	LA	MS	AL	FL	Sum
Units Supplied Locally	11.47	6.90	4.05	46.91	0.94	70.28
Proportion for Each State	16.33%	9.82%	5.76%	66.75%	1.34%	100%
Allocate Five-State GOM Region RS to Each State	4.44%	2.67%	1.57%	18.15%	0.36%	27.19%

Source: ERG estimates derived from IMPLAN data.

5.2.4 Separating Each State Into "GOM" and "Rest of" Regions

For each state, ERG developed separate IMPLAN models for the counties or parishes within the "GOM" region or "Gulf coast economic impact area" of that state (the green areas in Figures 4 and 5) and the "Rest of" that state. In Figures 4 and 5, the "Rest of" state regions are represented by the light gray area that lies between the green and dark gray areas, shown by the double-headed arrow pointing to the left of center.

To estimate the portion of spending that occurs in the "Rest of" state regions, ERG examined the ratio of the GOM RS in a state to the RS for each state. That is, the numerator is the RS for a GOM subset of counties (or parishes) in the state, while the denominator is the RS for entire state. For example, the RS for coal in Louisiana is 6.9 percent (see first line of Table 37) while the RS for the 40-parish Louisiana Gulf Coast Economic Impact Area is 0.59 percent (not shown). That is, the Louisiana Gulf Coast EIA's RS is 8.57 percent of the state's RS (0.59/6.9). The onshore distribution for coal in the 40-parish LA Gulf Coast EIA is then calculated as the product of the adjusted state RS (for Louisiana, this is the 2.67 percent from Table 37 line 3) and the ratio of the Gulf Coast EIA RS in a state to that state's RS (for Louisiana, this is the 8.57 percent calculated above). In the example of Louisiana, the calculation is thus 2.67 percent times 8.57 percent or 0.23 percent. To represent the Rest of Louisiana, the 0.23 percent is subtracted from 2.67 percent, producing an estimated RS for the Rest of Louisiana of 2.44 percent.

5.2.5 Separating State GOM Regions into Individual Counties or Parishes

In the example above, the 40-county region in Louisiana supplies 0.23 percent of the coal demanded. ERG divides the state Gulf Coast EIA region portion equally among all counties or parishes within the state. For example, each Louisiana parish in the Gulf Coast EIA region is assigned 1/40 of the 0.23 percent. This is because we do not know 1) where the money will go within this region and 2) how the individual counties will be grouped into economic regions for the analysis.

5.2.6 Observations

The first observation is that specific industries, such as G&G prospecting, might be concentrated in a few areas, such as Houston, rather than being equally distributed within the state coastal EIA regions. Section 5.3 describes how the onshore distribution of specific industry sectors important to offshore oil and gas operations are tailored to that industry. However, for the 400+ of the 440 IMPLAN sectors of lesser importance to offshore oil and gas operations, the methodology provides a consistent approach for estimating the onshore distributions of these expenditures.

The second observation is that the approach differs from that in the previous model documentation (USDOI MMS 2005).[20] The 2005 report examined Census data in County Business Pattern (CBP) and considered there to be an inconsistency when CBP data showed only one establishment while IMPLAN showed a high RS for the same sector. In these cases, the earlier report modified the onshore distribution if another sector within the same three-digit NAICS code was similar enough to substitute for the original data. The difficulty with this approach is that the CBP data are not inconsistent. It is possible that a single large facility could produce enough of a commodity or service to fill a large portion of the regional demand. Therefore, we believe the approaches outlined in Sections 5.2 and 5.3 will produce a more accurate estimate of RPs compared to the previous version.

[20] Page 32 implies that "Other US" includes both "Other US" as defined here plus the ROW.

5.3 INDUSTRY-SPECIFIC ONSHORE DISTRIBUTIONS

5.3.1 Oil Service Contract Industries

This section relies on *Analysis of the Oil Services Contract Industry in the Gulf of Mexico Region* (ERG 2011). The report examined 2007 data for 17 oil service industries[21] and identified about 1,140 locations supporting about 63,000 employees and accounting for an estimated $19.3 billion in revenues. Revenue and/or employment data was located for 76 percent of the locations. These data are the preliminary basis for developing onshore distributions for eight IMPLAN sectors (see Table 38).

Table 38

Oil Service Industries and IMPLAN Sectors

Oil Service Industry	IMPLAN Sector Number	IMPLAN Sector Name
Contract Drilling	28	Drilling Oil and Gas Wells
Drilling Fluid		
Mud Logging		
Measurement While Drilling		
Cementing		
Formation Evaluation		
Workover		
Completion		
Diving		
Fishing	29	Support Activities for Oil and Gas Operations
Drilling Tools		
Wellhead Equipment	206	Oil and Gas Field Equipment and Machinery
Air Transportation	332	Air Transportation
Water Transportation	334	Water Transportation
Geological and Geophysical Prospecting	369	Architectural and Engineering Services
Accommodations	412	Other Accommodations
Food Services	413	Food Services

Source: ERG (2011).

As mentioned earlier, approximately 24 percent of the locations did not have revenue or employment information. ERG imputed revenues for these locations by several methods:

- Where we had company revenues and the number of locations, we used the average revenue for each location. Petroleum Helicopters, Inc. (PHI), for example, does not list revenues for any of its 12 locations, but ERG could find revenues for the entire company. Thus, we assigned 1/12 of the revenues to each location.

[21] Geological and geophysical prospecting, contract drilling, drilling fluid supplies, drilling tools and supplies, mud logging, measurement while drilling (MWD), cementing, formation evaluation, completion, fishing, wellhead equipment suppliers, accommodations, air transport, water transport, catering, workovers, and diving support.

- Where we had company revenues and revenues for some (but not all) locations, ERG calculated the difference between total company revenues and the sum of location revenues and then divided the difference equally among the locations that lacked revenue data.

- Where we had the number of employees at a location but not the associated revenues, ERG calculated the average revenues per employee for that sector and multiplied it by the number of employees.

- Where we lacked both employee and revenue data for a single-location company, we used the average revenue per location for that sector.

Although a small amount of uncertainty is introduced by imputing missing data, the alternative would be to allocate nothing to a county or parish where we know there is economic activity in that sector within that region.[22]

For the eight IMPLAN sectors shown in Table 38, we assumed that all demand from offshore oil and gas operations would be filled from within the five-state region. Thus, the onshore allocations for the ROW and the Rest of the United States are set to 0 percent.

For some sectors, ERG (2011) identified locations that provided these services that are outside of the local economic region; these are assigned to the Rest of Texas, Rest of Louisiana, Rest of Mississippi, Rest of Alabama, and Rest of Florida regions, as appropriate.

The onshore distribution is calculated by county/parish according to the location revenues within the county or parish. For IMPLAN sector 29 (support activities for oil and gas operations), ERG aggregated the data as shown in Table 38. For IMPLAN Sector 206 (oil and gas field equipment and machinery), ERG needed to extend the analysis to address additional industries such as platform fabrication, subseabed completion equipment manufacturers, and insurance. The analysis is discussed in the next section.

5.3.2 New Industries

For this project, ERG developed onshore distributions for platform fabrication, materials associated with subseabed completions, FPSOs, and insurance. Each is discussed in its own section below.

5.3.2.1 Platform Fabrication

In 2009, the platform fabrication industry in the GOM supported more than 23,000 jobs and represented approximately $3.7 billion in gross revenues. Appendix D contains the data and methodology used to estimate the GOM onshore distribution for this industry sector. Fixed platforms tend to be made in the GOM. Hulls for semisubmersible platforms, however, tend to be made outside of the United States. Hull costs are approximately 7.5 percent of the semisubmersible costs (see Appendix E). For the purpose of not overestimating the contributions of industry expenditures in the GOM to the adjacent regions, ERG set the ROW to 7.5 percent

[22] The imputation of missing data also means that the onshore allocations will differ slightly from the summary tables in ERG (2011).

and decreased the contributions to the GOM parishes and counties proportionately (see Table 39).[23] The onshore distribution is assigned to IMPLAN Sector 290 (shipbuilding and repairing).

Table 39

Onshore Distribution for the Platform Fabrication Activity

State	County/Parish	Revenue (Millions)	Percent	Adjusted Percent
AL	Mobile	$35.16	0.94%	0.87%
LA	Iberia	$433.75	11.63%	10.76%
LA	Jefferson (LA)	$41.16	1.10%	1.02%
LA	Lafayette	$9.40	0.25%	0.23%
LA	Lafourche	$0.60	0.02%	0.01%
LA	Plaquemines	$67.13	1.80%	1.66%
LA	Saint Mary	$131.85	3.54%	3.27%
LA	Terrebonne	$387.43	10.39%	9.61%
LA	Vermilion	$32.05	0.86%	0.79%
MS	Jackson	$398.00	10.67%	9.87%
MS	Warren	$249.06	6.68%	6.18%
TX	Brazoria	$5.24	0.140%	0.130%
TX	Cameron (TX)	$270.50	7.25%	6.71%
TX	Galveston	$4.50	0.12%	0.11%
TX	Harris	$298.42	8.00%	7.40%
TX	Jefferson (TX)	$19.88	0.53%	0.49%
TX	Nueces	$420.62	11.28%	10.43%
TX	Orange	$29.30	0.79%	0.73%
TX	San Patricio	$895.54	24.01%	22.21%
ROW				7.50%

Source: Appendix E.

5.3.2.2 Subsea Completions

Subsea systems have one or more subsea wells, manifolds, control umbilicals, pumping/processing equipment, or flow lines (USDOI MMS 2008). Five companies dominate the subsea production equipment market: Aker Solutions, Cameron International, Dril-Quip, FMC, and Vetco Gray (General Electric Oil and Gas) (Kopits and Jones 2010). During 2007–2009, FMC held about 45 to 47 percent of the market, Cameron and Vetco Gray held about 17 to 16 percent each, Aker Solutions garnered 13 percent, and Dril-Quip held the remaining 7 percent (Kopits and Jones 2010).

Aker is reported to have held 65 percent of the global steel tube umbilical market in 2008. The company has an umbilical manufacturing plant in Mobile, Alabama, where 90 percent of the workforce is from Mobile and the surrounding area (Alabama 2008). Umbilicals for the GOM are likely to originate at this plant and other regional facilities.

Cameron International has subsea manufacturing facilities in Berwick, Louisiana, as well as Leeds, England, and Johor, Malaysia (Cameron 2009). FMC lists production facilities for its

[23] The datasets supporting MAG-PLAN V2 indicate that the 2005 model has an onshore allocation of 91 percent of expenditures in the shipbuilding and repairing sector going to the “Other U.S.” region. While there are major shipbuilding yards on the East and West Coasts, they do not manufacture offshore oil and gas platforms.

Energy Production Systems segment in Houston, Texas, and Oklahoma City, Oklahoma, and subsea systems accounted for 62 to 70 percent of FMC's total revenues for 2007–2009. FMC has 16 other manufacturing locations spread around the globe (FMC 2009). GE entered the oil and gas market with its acquisition of VetcoGray in 2007. VetcoGray's manufacturing facility remains in Houston, Texas (GE 2008), and GE also lists a manufacturing operation in Harvey, Louisiana (GE 2010). Dril-Quip has two manufacturing locations in Houston, Texas (Dril-Quip 2009).

ERG searched the D&B database (D&B 2010) for revenues associated with each of the locations (see Table 40). We integrated the information in Table 40 with the data for drilling tools and wellhead equipment in ERG (2011) to develop the onshore distribution for IMPLAN Sector 206 (mining and oil and gas field equipment and machinery).[24,25] That is, the revenues and locations shown in Table 40 were added to those in ERG (2011), and the percentage of total revenues per county and parish were recalculated.

Table 40

Subsea Equipment Manufacturers

Name	Owner	City	State	County	2009 Revenues (Millions)	Percent
Aker Subsea		Mobile	AL	Mobile	$75.0	16.29%
Energy Production Systems	FMC	Houston	TX	Harris	$7.4	1.61%
Energy Production Systems	FMC	Oklahoma City	OK	Oklahoma	$1.5	0.33%
Vetco Gray	GE	Houston	TX	Harris	$148.3	32.21%
Vetco Gray	GE	Harvey	LA	Jefferson	$12.7	2.76%
Dril-Quip		Houston	TX	Harris	$186.0	40.40%
Cameron International		Berwick	LA	St. Mary	$29.5	6.40%
Total					$460.4	100.00%

Source: ERG estimates

ERG incorporated the findings of the June 2011 report by Quest Offshore Resources that indicated approximately 23% of oil and gas field equipment and machinery is manufactured outside of the GOM region (Quest Offshore Resources 2011). Table 41 presents the onshore distribution for IMPLAN Sector 206.

[24] During the integration, we identified that the Vetco Gray facility in Harvey, Louisiana, shown in Table 40 had already been captured in the wellhead equipment category in ERG (2011).

[25] At this time, MAG-PLAN does not support multiple onshore distributions for a single IMPLAN sector depending on the activity.

5.3.2.3 FPSOs

The FPSO Activity Function is modeled as the vessel and associated subsea completion(s). Appendix C documents the data for an estimated vessel cost of $1.9 billion and a subsea completion cost of $200 million for a total cost of $2.1 billion. Thus, 9.52 percent of the activity cost ($200 million/$2.1 billion) is allocated to IMPLAN Sector 206 (mining and oil and gas field machinery) while the remaining 90.48 percent of the activity cost is allocated to IMPLAN Sector 290 (shipbuilding and repairing).

5.3.2.4 Insurance

Cost data for deep offshore wells collected by USDOE's NETL indicates that insurance costs might represent as much as 11.9 percent of exploratory well costs but only 1.3 percent of development well costs (USDOE NETL 2005; ERG 2011). ERG examined the offshore insurance market to understand the onshore distribution of nearly 12 percent of exploratory well costs.

Dismukes and Peters (2011) provide an excellent overview of the types of offshore energy insurance in the course of examining the post-2004 changes in these insurance markets. These include, but are not limited to, self-insurance, mutualization, private insurance, and reinsurance. In self-insurance, an oil and gas company sets up an account to pay for losses from unforeseen events. Self-insurance is possible for major oil companies, particularly those whose assets exceed those of most insurance companies. In effect, the company pays the premiums to itself rather than to an insurance company. Mutualization describes the process of a group of companies organizing a joint pool that insures each member against different types of adverse incomes. Oil Insurance Limited (OIL) is the premier example of a mutual insurance company. One requirement for membership, however, is at least $1 billion in gross assets, and so, like self-insurance, it is limited to large companies. Private insurance is commercial insurance. Lloyd's of London is an insurance exchange where insurers and brokers can meet (much like a stock exchange). Reinsurers insure the insurance companies. This secondary market helps to diversify the risk of the primary insurance companies. Most companies use a mix of insurance types to meet their needs.

Table 41

Onshore Distribution for IMPLAN Sector 206—Oil And Gas Field Equipment And Machinery

State	County/Parish	Percent
AL	Mobile	1.14%
LA	Ascension	0.00%
LA	Calcasieu	0.58%
LA	Cameron	0.01%
LA	Iberia	2.24%
LA	Jefferson	1.00%
LA	Lafayette	6.52%
LA	Lafourche	0.18%
LA	Orleans	1.31%
LA	Plaquemines	1.21%
LA	St. Landry	0.08%
LA	St. Martin	0.64%
LA	St. Mary	1.20%
LA	St. Tammany	0.30%
LA	Terrebonne	2.23%
LA	Vermilion	0.03%
TX	Brazoria	0.17%
TX	Cameron	0.01%
TX	Fort Bend	1.09%
TX	Harris	48.73%
TX	Hidalgo	0.29%
TX	Jefferson	0.03%
TX	Jim Wells	0.94%
TX	Montgomery	3.01%
TX	Nueces	0.89%
TX	San Patricio	0.04%
TX	Victoria	0.49%
TX	Waller	0.63%
TX	Wharton	0.04%
LA	Rest of LA	1.15%
TX	Rest of TX	0.83%
	Rest of US	23.00%
Sum		100.00%

Source: ERG estimates based on ERG (2011) and Table 40.

Dismukes and Peters (2011) summarizes the share of losses borne by self-insurers; OIL; and the commercial market from Hurricanes Ivan, Katrina, Rita, and Ike (see Table 42). If we assume that the insurance patterns for the assets damaged or destroyed by the hurricanes are typical of the insurance patterns for the GOM, self-insurers (industry) absorbed from 3 to 46 percent of the losses, OIL absorbed between 10 and 30 percent of the losses, and commercial insurers absorbed between 42 and 67 percent of the losses.

On a combined basis, about one-third of the insurance coverage is provided by the oil and gas companies themselves. In 2009, Willis Group Holdings noted that a smaller exploration and production company might find it more advantageous to self-insure given premium and loss limits (Willis Group Holdings 2009). As reported in *Rigzone*, a 2010 study by IHS Global Insight noted that independents are the largest shareholder in 66 percent of the 7,521 leases in the entire Gulf and in 81 percent of producing leases (Rigzone 2010). Thus, we might infer that between 22 and 28 percent of the insurance coverage is self-insurance by independent oil and gas companies. ERG also infers that this expenditure is likely to stay within the United States, while self-insurance expenditures by major firms with multinational interests are likely to go outside the United States. ERG uses the mid-point of the range (25 percent) for the onshore allocation to remain in the United States.

Table 42

Gulf of Mexico Insurance and Hurricane Losses

Metric	Hurricane				Combined
	Ivan	Katrina	Rita	Ike	
Total Loss (Millions, current)	$1,859	$7,078	$5,557	$5,949	$20,443
Estimated Losses (Millions) Borne by:					
Industry	$49	$3,268	$1,257	$2,349	$6,923
OIL	$560	$810	$800	$600	$2,770
Commercial Market	$1,250	$3,000	$3,500	$3,000	$10,750
Share of Losses Borne by:					
Industry	3%	46%	23%	39%	34%
OIL	30%	11%	14%	10%	14%
Commercial Market	67%	42%	63%	50%	53%

Source: Dismukes and Peters (2011)

This means that the sum of the insurance expenditures associated with the commercial market (53 percent), OIL (14 percent), and self-insurance by major oil companies (8 percent), or 75 percent of the expenditures associated with NAICS 5241 (IMPLAN industry 357, insurance carriers), is very likely to go outside of the United States.[26]

Although it is more likely that the remaining 25 percent of spending in IMPLAN industry 357 would remain within the five-state GOM region rather than going elsewhere within the United States, ERG could not locate information to support a more detailed distribution of the spending. As a result, ERG assigned the 25 percent to the Rest of the United States.

Finally, ERG examined oil and gas insurance companies as listed in the 2008 Gulf Coast Oil Directory. ERG removed companies that insured only vessels and those that insured only onshore operations and found 29 companies that indicated they provided coverage for offshore oil and gas operations. All of these companies fall under NAICS 5242 (IMPLAN industry 358, insurance agents). Unfortunately, many of the largest companies (e.g., Texas Mutual Insurance Company) have substantial activities in other areas as well. ERG examined the RPs for this industry and found that they were very high in each county/parish. Thus, insurance costs are likely to be internally supplied wherever the expenditure is made. As a result, ERG did not pursue a geographic refinement of this industry but remained with the distribution as calculated with the Section 5.2 methodology.

5.4 ONSHORE DISTRIBUTIONS FOR LABOR

MAG-PLAN divides expenditures in to non-labor and labor spending (see Chapter 2.0). As seen in the previous sections, MAG-PLAN uses a sector-by-onshore-area matrix to distribute the spending to onshore areas. In contrast, MAG-PLAN uses an activity function-by-onshore-area matrix for the labor onshore distribution. For all but four Activity functions, [27] workers are assumed to live within commuting distance of their work place.

The four exceptions are the three drilling activity functions and the production function. Offshore oil and gas work schedules, particularly for those in operations on offshore production structures, frequently take a “multiweek period on/multiweek period off” format. Thus, offshore oil and gas workers have the flexibility to live substantial distances away from the GOM region. This phenomenon was investigated by the Labor Needs Survey, which developed a distribution of the percent of the labor force by home ZIP code (ICF 2008, hereafter called “LNS”). To protect the confidentiality of workers’ home addresses, ICF aggregated data by 1-, 2-, or 3-digit ZIP codes as well as by state and multistate areas. For use in MAG-PLAN, however, the onshore distribution for labor in four Activity Functions needs to be distributed among counties and parishes.

Table 43 is a copy of the ZIP code, area, and percentage data from the LNS. LNS does not provide a finer breakdown of the data and ZIP code boundaries do not necessarily correspond to county or parish boundaries. Table 44 is the list of the LNS ZIP code areas that correspond to a single county or MAG-PLAN region. ZIP code 770 lies entirely within Harris County, TX. The

[26] Dismukes and Peters (2011) note that Watkins Syndicate is the largest direct insurer in the GOM. Watkins Syndicate and Munich Reinsurance (the world’s largest reinsurer) are foreign companies, as is the Lloyd’s exchange.

[27] Drilling (exploratory, non-productive development, and productive development wells) and production operations and maintenance.

other ZIP codes in Harris County, TX are discussed further below. No further adjustment needs to be made to the Table 44 data for use in MAG-PLAN.

For the other two- and three-digit ZIP code regions, ERG began by visually overlaying the ZIP code map on t he state map of counties/parishes (GoToMyList.com 2012; U.S. Census Bureau 2012a). ERG noted which counties/parishes fell completely within the ZIP code and those which were only partially within a ZIP code. For all counties/parishes within a ZIP code, ERG downloaded 2010 labor force data from American Factfinder (U.S. Census Bureau, 2012). The entire labor force was counted for counties/parishes that lay entirely within the ZIP code. One-half of the labor force was counted for counties/parishes that lay partly in the ZIP code. The exception is Harris County, Texas. ZIP code 770 lies entirely within Harris County and is assumed to represent 70% of the labor force. Harris County also includes parts of ZIP codes 773, 774, and 775. ERG assigned 10% of the Harris County labor force to each of these ZIP codes.

Table 43

Onshore Distribution for Labor in Offshore Oil and Gas Operations

ZIP Code	Area	Percent
32	Northern Florida	1.94%
36	Mobile, Montgomery, AL	3.33%
39	Biloxi, Jackson, Southern MS	4.28%
	Arkansas & Tennessee	0.82%
700	Metairie, Chalmette, LA	3.67%
701	New Orleans, LA	0.66%
703	Houma, Donaldsonville, LA	20.78%
704	Hammond, Ponchatoula, Bogalusa, LA	4.62%
705	Lafayette, New Iberia, Abbeville, LA	18.75%
706	Lake Charles, LA	1.40%
	Other South LA	0.58%
71	Shreveport, LA	4.01%
75-76	Dallas & Forth Worth	0.89%
770	Houston, TX	9.81%
773	Humble, Kingwood, Spring, TX	9.14%
774	Katy, Park Row, Sugarland, TX	1.20%
775	Deer Park, Galveston, Pearland, TX	5.23%
	Other Coastal TX	0.69%
78	Austin, Corpus Christi, San Antonio, TX	6.46%
9	West Coast	0.79%
	Other Lower 48	0.94%
	Sum	99.99%

Source: ICF 2008, Table 5.4

Table 44

Labor Onshore Distribution: No Adjustments

ZIP Code	Area	Percent	MAG-PLAN Region
	Arkansas & Tennessee	0.82%	Rest of US
	Other South LA	0.58%	Rest of LA
71	Shreveport, LA	4.01%	Rest of LA
75-76	Dallas & Forth Worth	0.89%	Rest of TX
770	Houston, TX	9.81%	Harris
	Other Coastal TX	0.69%	Rest of TX
78	Austin, Corpus Christi, San Antonio, TX	6.46%	Rest of TX
9	West Coast	0.79%	Rest of US
	Other Lower 48	0.94%	Rest of US

Source: ICF 2008, Table 5.4

The approach is illustrated for Texas in Table 45. The columns labeled "Weights" is the fraction of the labor force in the ZIP code region that falls within a county. For example, in ZIP code 773, the regional employment is the sum of employment of Montgomery, Walker, and Polk Counties (254,998), half the employment in Liberty County (16,052), and one-tenth the employment in Harris County (203,867). That is, the labor force in ZIP code 773 is an estimated 474,917. Montgomery County, with its labor force of 215,426 accounts for 45.4% of the ZIP code labor force.

The next column, "LNS Percent," is the fraction of the offshore workforce in that ZIP code (see Table 43). The LNS percent is multiplied by the weight to calculate the "Allocated Percent." For Montgomery County, the calculation is 45.4% times 9.14% or 4.15%.

Because several counties are located in more than one ZIP code region, the allocated percents must be summed back to county totals (rightmost columns). For example, the 1.11% for Brazoria County reflects the 0.14% from ZIP code 774 plus 0.97% from ZIP Code 775. The labor percentage for Harris County reflects the sum of 9.81% from ZIP code 770 (see Table 44), 3.92% from ZIP code 773, 0.39% from ZIP code 774, and 2.70% from ZIP code 775.

Table 46 shows the same calculations for Louisiana.

Table 45

Texas Onshore Labor Distribution

		Allocation					Summary	
ZIP code	County	All/Part	Total County Labor Force	Weights	LNS Percent	Allocated Percent	County	Percent
	Montgomery	All	215,426	45.4%		4.15%	Austin	0.01%
	Walker	All	22,671	4.8%		0.44%	Brazoria	1.11%
	Polk	All	16,901	3.6%		0.33%	Chambers	0.21%
	Liberty	Part	32,104	3.4%		0.31%	Colorado	0.01%
773	Harris	Part	2,038,674	42.9%	9.14%	3.92%	Fort Bend	0.53%
	Waller	All	20,404	3.29%		0.04%	Galveston	0.97%
	Fort Bend	All	273,604	44.05%		0.53%	Hardin	0.17%
	Wharton	All	20,542	3.31%		0.04%	Harris	16.82%
	Matagorda	All	17,282	2.78%		0.03%	Liberty	0.52%
	Brazoria	Part	147,009	11.83%		0.14%	Matagorda	0.03%
	Colorado	Part	9,497	0.76%		0.01%	Montgomery	4.15%
	Austin	Part	14,272	1.15%		0.01%	Polk	0.33%
774	Harris	Part	2,038,674	32.82%	1.20%	0.39%	Walker	0.44%
	Chambers	All	15,815	4.00%		0.21%	Waller	0.04%
	Liberty	Part	32,104	4.06%		0.21%	Wharton	0.04%
	Hardin	Part	25,103	3.17%		0.17%		
	Galveston	Part	147,417	18.64%		0.97%		
	Brazoria	Part	147,009	18.59%		0.97%		
775	Harris	Part	2,038,674	51.55%	5.23%	2.70%		

Source: ERG estimates based on GoToMyList.com (2012); U.S. Census Bureau (2012a); and ; U.S. Census Bureau (2012b).

Table 46

Louisiana Onshore Labor Distribution

ZIP code	Parish	Allocation					Summary	
		All/Part	Total Parish Labor Force	Weights	LNS Percent	Allocated Percent	Parish	Percent
	Plaquemines	All	10,217	5.4%		0.20%	Acadia	1.85%
	St. Bernard	All	13,257	7.0%		0.26%	Allen	0.05%
	St. Charles	All	26,601	14.0%		0.51%	Ascension	3.68%
	St. John the Baptist	All	22,987	12.1%		0.44%	Assumption	1.44%
	Jefferson	Part	224,767	59.0%		2.16%	Beauregard	0.16%
700	St. James	Part	10,285	2.7%	3.67%	0.10%	Calcasieu	0.98%
	Orleans	All	150,066	57.18%		0.38%	Cameron	0.04%
701	Jefferson	Part	224,767	42.82%	0.66%	0.28%	Evangeline	0.45%
	Assumption	All	10,061	6.91%		1.44%	Iberia	2.33%
	Lafourche	All	44,628	30.66%		6.37%	Jefferson	2.45%
	Terrebonne	All	52,181	35.84%		7.45%	Jefferson Davis	0.54%
	Ascension	Part	51,623	17.73%		3.68%	Lafayette	7.90%
703	St. Mary	Part	25,788	8.86%	20.78%	1.84%	Lafourche	6.37%
	St. Helena	All	4,891	2.23%		0.10%	Livingston	0.63%
	St. Tammany	All	110,796	50.54%		2.33%	Orleans	0.38%
	Tangipahoa	All	55,125	25.14%		1.16%	Plaquemines	0.20%
	Washington	All	18,601	8.48%		0.39%	St. Bernard	0.26%
704	Livingston	Part	59,642	13.60%	4.62%	0.63%	St. Charles	0.51%
	Acadia	All	26,888	10.02%		1.85%	St. Helena	0.10%
	Iberia	All	33,755	12.58%		2.33%	St. James	0.10%
	Lafayette	All	114,566	42.69%		7.90%	St. John the Baptist	0.44%
	St. Martin	All	24,055	8.96%		1.66%	St. Landry	1.18%
	Vermilion	All	25,806	9.62%		1.78%	St. Martin	1.66%
	Evangeline	Part	13,039	2.43%		0.45%	St. Mary	2.73%
	Jefferson Davis	Part	13,531	2.52%		0.47%	St. Tammany	2.33%
	St. Landry	Part	34,245	6.38%		1.18%	Tangipahoa	1.16%
705	St. Mary	Part	25,788	4.80%	18.50%	0.89%	Terrebonne	7.45%
	Beauregard	All	15,123	11.48%		0.16%	Vermillion	0.00%
	Calcasieu	All	92,007	69.84%		0.98%	Vernon	0.10%
	Cameron	All	3,632	2.76%		0.04%	Washington	0.39%
	Allen	Part	9,527	3.62%		0.05%		
	Jefferson Davis	Part	13,531	5.14%	1.40%	0.07%		
706	Vernon	Part	18,879	7.17%		0.10%		

Source: ERG estimates based on GoToMyList.com (2012); U.S. Census Bureau (2012a); and U.S. Census Bureau (2012b).

Tables 47 and 48 show the calculations for Mississippi (ZIP code 39) and Alabama (ZIP code 36), respectively. For these states, the two-digit ZIP codes cover a substantial portion of the state. Each county is flagged by whether or not it is in the "Rest of" state region. The percentages for the counties flagged as "Y" are summed to estimate the "Rest of" allocation. For Mississippi, the "Rest of MS" is 2.77% and, for Alabama, the "Rest of AL" is 1.74%.

Table 47

Mississippi Onshore Labor Distribution

County	Allocation					Rest of MS
	All/Part	Total County Labor Force	Weights	LNS Percent	Allocated Percent	
Adams	All	13,810	1.5%		0.06%	Y
Amite	All	5,060	0.5%		0.02%	N
Attala	All	8,473	0.9%		0.04%	Y
Choctaw	All	3,802	0.4%		0.02%	Y
Claiborne	All	4,000	0.4%		0.02%	Y
Clarke	All	7,207	0.8%		0.03%	Y
Clay	All	9,325	1.0%		0.04%	Y
Copiah	All	12,613	1.3%		0.06%	Y
Covington	All	8,494	0.9%		0.04%	Y
Forrest	All	36,505	3.8%		0.16%	N
Franklin	All	3,274	0.3%		0.01%	Y
George	All	9,218	1.0%		0.04%	N
Greene	All	4,482	0.5%		0.02%	N
Hancock	All	19,445	2.0%		0.09%	N
Harrison	All	93,578	9.8%		0.42%	N
Hinds	All	119,964	12.6%		0.54%	Y
Holmes	All	7,401	0.8%		0.03%	Y
Humphreys	All	3,756	0.4%		0.02%	Y
Issaquena	All	729	0.1%		0.00%	Y
Jackson	All	66,877	7.0%		0.30%	N
Jasper	All	7,466	0.8%		0.03%	Y
Jefferson	All	2,537	0.3%		0.01%	Y
Jefferson Davis	All	5,239	0.6%		0.02%	Y
Jones	All	29,027	3.1%		0.13%	Y
Kemper	All	3,809	0.4%		0.02%	Y
Lamar	All	26,654	2.8%		0.12%	N
Lauderdale	All	37,091	3.9%		0.17%	Y
Lawrence	All	5,437	0.6%		0.02%	Y
Leake	All	8,983	0.9%		0.04%	Y
Lincoln	All	14,801	1.6%		0.07%	Y
Lowndes	All	28,718	3.0%		0.13%	Y
Madison	All	47,110	5.0%		0.21%	Y
Marion	All	10,563	1.1%		0.05%	N
Neshoba	All	12,693	1.3%		0.06%	Y
Newton	All	9,550	1.0%		0.04%	Y
Noxubee	All	4,728	0.5%		0.02%	Y
Oktibbeha	All	22,935	2.4%		0.10%	Y
Pearl River	All	24,216	2.5%		0.11%	N
Perry	All	5,426	0.6%	4.28%	0.02%	N

Table 47.

Mississippi Onshore Labor Distribution (cont.)

County	Allocation					Rest of MS
	All/Part	Total County Labor Force	Weights	LNS Percent	Allocated Percent	
Pike	All	16,551	1.7%		0.07%	N
Rankin	All	71,596	7.5%		0.32%	Y
Scott	All	12,813	1.3%		0.06%	Y
Simpson	All	12,609	1.3%		0.06%	Y
Smith	All	7,166	0.8%		0.03%	Y
Stone	All	7,306	0.8%		0.03%	N
Warren	All	23,877	2.5%		0.11%	Y
Walthall	All	5,954	0.6%		0.03%	N
Wayne	All	8,592	0.9%		0.04%	Y
Webster	All	4,451	0.5%		0.02%	Y
Wilkinson	All	3,485	0.4%		0.02%	N
Winston	All	8,669	0.9%		0.04%	Y
Yazoo	All	11,471	1.2%		0.05%	Y
Monroe	Part	16,859	0.9%		0.04%	Y
Montgomery	Part	4,741	0.2%		0.01%	Y
Sharkey	Part	2,149	0.1%	4.28%	0.00%	Y

Source: ERG estimates based on GoToMyList.com (2012); U.S. Census Bureau (2012a); and ; U.S. Census Bureau (2012b).

Table 48

Alabama Onshore Labor Distribution

County	Allocation					Rest of AL
	All/Part	Total County Labor Force	Weights	LNS Percent	Allocated Percent	
Autauga	All	26,635	2.8%		0.09%	Y
Baldwin	All	84,253	8.8%		0.29%	N
Barbour	All	10,966	1.2%		0.04%	Y
Bullock	All	4,854	0.5%		0.02%	Y
Butler	All	8,994	0.9%		0.03%	N
Calhoun	All	50,958	5.4%		0.18%	Y
Chambers	All	15,951	1.7%		0.06%	Y
Choctaw	All	5,156	0.5%		0.02%	N
Clarke	All	9,072	1.0%		0.03%	N
Clay	All	6,461	0.7%		0.02%	Y
Cleburne	All	6,547	0.7%		0.02%	Y
Coffee	All	22,496	2.4%		0.08%	Y
Conecuh	All	5,091	0.5%		0.02%	N
Covington	All	17,305	1.8%		0.06%	N
Crenshaw	All	6,436	0.7%		0.02%	Y
Dale	All	24,275	2.5%		0.08%	Y
Dallas	All	18,168	1.9%		0.06%	N
Elmore	All	36,203	3.8%		0.13%	Y
Escambia	All	14,918	1.6%		0.05%	N
Geneva	All	12,125	1.3%		0.04%	N
Henry	All	8,033	0.8%		0.03%	Y
Houston	All	47,309	5.0%		0.17%	N
Lee	All	68,545	7.2%		0.24%	Y
Lowndes	All	4,915	0.5%		0.02%	N
Macon	All	9,308	1.0%		0.03%	Y
Marengo	All	8,482	0.9%		0.03%	N
Mobile	All	193,846	20.4%		0.68%	N
Monroe	All	9,731	1.0%		0.03%	N
Montgomery	All	112,883	11.9%		0.39%	Y
Perry	All	3,957	0.4%		0.01%	N
Pike	All	15,642	1.6%		0.05%	Y
Randolph	All	10,019	1.1%		0.04%	Y
Russell	All	24,141	2.5%		0.08%	Y
Tallapoosa	All	19,568	2.1%		0.07%	Y
Washington	All	7,209	0.8%		0.03%	N
Wilcox	All	3,232	0.3%		0.01%	N
Chilton	Part	20,222	1.1%		0.04%	Y
Greene	Part	3,692	0.2%		0.01%	Y
Hale	Part	7,007	0.4%		0.01%	Y
Sumter	Part	6,406	0.3%	3.33%	0.01%	Y

Source: ERG estimates based on GoToMyList.com (2012); U.S. Census Bureau (2012a); and ; U.S. Census Bureau (2012b).

Table 49 shows the calculations for Florida. In this case, ZIP codes beginning with "32"extend across northern Florida and down the east coast of the state. ERG limited the counties in the analysis to those identified across northern Florida in the 2005 M AG-PLAN technical report. That is, counties along the East Coast of Florida are excluded. This is consistent with the findings in Fannin et al. (2011).

Table 49

Florida Onshore Labor Distribution

County	Allocation				
	All/Part	Labor Force	Weights	LNS Percent	Allocated Percent
Alachua	All	125,027	12.7%		0.42%
Bay	All	87,101	8.8%		0.29%
Bradford	All	11,645	1.2%		0.04%
Calhoun	All	4,933	0.5%		0.02%
Columbia	All	29,640	3.0%		0.10%
Dixie	All	5,757	0.6%		0.02%
Escambia	All	150,620	15.3%		0.51%
Franklin	All	5,277	0.5%		0.02%
Gadsden	All	18,063	1.8%		0.06%
Gilchrist	All	7,423	0.8%		0.03%
Gulf	All	6,095	0.6%		0.02%
Hamilton	All	5,121	0.5%		0.02%
Holmes	All	7,405	0.8%		0.03%
Jackson	All	18,293	1.9%		0.06%
Jefferson	All	6,509	0.7%		0.02%
Lafayette	All	3,726	0.4%		0.01%
Leon	All	149,358	15.1%		0.50%
Liberty	All	3,678	0.4%		0.01%
Madison	All	8,230	0.8%		0.03%
Okaloosa	All	98,337	10.0%		0.33%
Santa Rosa	All	73,712	7.5%		0.25%
Suwannee	All	17,441	1.8%		0.06%
Taylor	All	10,007	1.0%		0.03%
Union	All	5,441	0.6%		0.02%
Wakulla	All	14,093	1.4%		0.05%
Walton	All	25,386	2.6%		0.09%
Washington	All	10,277	1.0%		0.03%
Levy	Part	17,354	0.9%		0.03%
Marion	Part	137,320	7.0%	3.33%	0.23%

Source: ERG estimates based on GoToMyList.com (2012); U.S. Census Bureau (2012a); and ; U.S. Census Bureau (2012b).

For some sectors, ERG assumed that people tended to live within a traditional commuting distance of where they worked. The distribution associated with specific activity functions is provided in Table 50.

Table 50

Activity Functions, Sectors, and Onshore Distributions

Activity Function	IMPLAN Sector	Onshore Distribution based on
Exploratory Drilling		Labor Needs Survey
Nonproductive Development Drilling		Labor Needs Survey
Development Drilling and Production		Labor Needs Survey
Geological & Geophysical Prospecting	369	Architectural, engineering, and related services
Platform Fabrication and Installation	209	Shipbuilding
FPSO		
Subseabed	206	Mining and oil and gas field equipment
Onshore Gas Processing Construction	35	Construction of new non-residential manufacturing structures
Offshore Pipeline Construction		
Decommission Platform (explosives)	29	Support activities for oil and gas operations
Decommission Platform (no explosives)		
Onshore Oil Spill	390	Waste management and remediation services
Offshore Oil Spill		
Production Operations and Maintenance	28	Labor Needs Survey
Onshore Gas Processing O&M		
Offshore Pipeline O&M		

Source: ERG estimates

5.5 MODIFYING THE ONSHORE DISTRIBUTIONS FOR WESTERN AND CENTRAL GOM AREAS

ERG developed additional onshore distributions for the western and central GOM areas[28] under the following assumptions:

- Assumption 1: Sectors that are likely to be provided by local vendors are retail and service sectors. These are IMPLAN sectors 320 and higher in the 440-industry scheme.
- Assumption 2: Texas provides locally to the western GOM while Louisiana provides locally to the central GOM.
- Assumption 3: The onshore distributions for sectors for which detailed distributions were developed (Section 5.3) might or might not differ for the Western and Central GOM areas.

For IMPLAN sectors 320 and higher, ERG retained the values for the Rest of United States, the ROW, and the Rest of State regions as developed in Section 5.2 (i.e., the distributions for the Rest of regions used for western and central GOM are the same as those used for GOM). We then summed these seven values (ROW and Rest of US, TX, LA, MS, AL, and FL). The difference between 100 percent and the aggregate sum is the onshore distribution within the 189 counties and parishes in the GOM region ("GOM onshore distribution"). For the western GOM, the distributions for the counties and parishes in Louisiana, Mississippi, Alabama, and Florida were set to zero and the GOM onshore distribution was divided equally among the 63 Texas counties. For the central GOM, the distributions for the counties in Texas, Mississippi, Alabama, and Florida were set to zero and the GOM onshore distribution was divided equally among the 40 Louisiana parishes.

For six sectors, detailed onshore distributions were not modified because they are unlikely to vary between operations in the Western and Central GOM regions:

- Sector 28 (drilling oil and gas wells)
- Sector 29 (support activities for oil and gas operations)
- Sector 206 (mining and oil and gas field equipment and machinery
- Sector 290 (shipbuilding and repairing)
- Sector 357 (insurance carriers)

[28] As with any modeling effort, there are always improvements and expansions to be made. Currently, we have insufficient information to develop datasets for the Eastern GOM region. For initial efforts, logistical support might be brought from existing businesses in the Central, or possibly Western GOM region(s). At this time, we do not know the "tipping point"; that is, the sustained level of activity needed for new businesses to begin in the coastal EGOM region. The geographic distribution for the West and Central GOM regions was developed from existing data on actual businesses and locations. These data do not yet exist for all economic aspects in the Eastern GOM region.

- Sector 412 (other accommodations)

Onshore distributions were modified for four sectors:

- Sector 332 (air transportation)

- Sector 334 (water transportation)

- Sector 369 (architectural, engineering, and related services)

- Sector 413 (food services)

For Sectors 332, 334, and 413, the services are assumed to originate in either the Western GOM or Central GOM. For Western GOM, the onshore distribution percentages for the Texas counties and Rest of Texas are summed and each subregion's share of the total Texas distribution is calculated. The Western GOM distribution is then based on these values (i.e., 100 percent is divided among the named Texas counties, based on each county's share of the total Texas counties' distribution calculated above). For the Central GOM, the same method is used except only Louisiana parishes are included.

The onshore distribution for Sector 369 (architectural, engineering, and related services) was not modified for the Central GOM because so much of these services originate in Texas. For the Western GOM, however, the small percentage (about 6%) of architectural, engineering, and related services distributed to Louisiana parishes in the Gulf-wide distribution is redistributed to Texas counties on the proportional basis described for Sectors 332, 334, and 413.

6.0 REVENUE FUNCTIONS

As mentioned in Section 2.4, revenue functions are:

- Bonus bids
- Rental payments
- Royalties on oil and gas production

These appear as six columns in an E&D scenario, where each revenue function is subdivided into 8(g) and non-8(g) categories.[29]

Figure 6 illustrates the revenue function logic flow within MAG-PLAN. The top box is labeled "Bonus, Rent or Royalty" because each revenue type is processed in the same manner. The first step is to separate the revenue type into non-8(g) and 8(g) revenue activities. All non-8(g) revenues go to the federal government. That is, 100 percent of the funds are assigned to the United States with the associated IMPLAN Sector 429 (federal government enterprises other than electric utilities).

The right-hand part of Figure 6 concerns the 8(g) revenues. These funds are split between the federal government and the GOM states. As with the non-8(g) funds, the 73 percent of the 8(g) funds that go to the federal government are allocated to IMPLAN Sector 429.

[29] The royalty data provided in the E&D scenario incorporates all royalty relief categories (i.e., Deepwater, Shallow Water Deep Gas, End-of-Life, and Special Case) (USDOI BOEM 2011).

The 27 percent of the 8(g) funds that go to the GOM states are divided among the states according to the state waters adjacent to the location of the site where the bonus, rent, or royalty was generated. The Office of Natural Resources Revenue provides total Federal offshore disbursements by state by year, including a line item for GOMESA funds. ERG subtracted the GOMESA funds from total disbursement to estimate the 8(g) funds disbursed to the state for that year. To estimate the percentages shown in Figure 6, ERG downloaded disbursement data by state for FY 2008–2010 from (USDOI ONRR 2011). After calculating the 8(g) funds for each state, ERG summed the entries to obtain the 5-state total for 8(g) funds and then calculated the percentage of total 8(g) funds dispersed to each state (see Table 45). The percentages shown in Figure 6 are the three-year averages (see Table 46). All state monies are allocated to IMPLAN Sector 432 (state and local government enterprises other than passenger transit or electric utilities).The Federal portion of 8(g) funds are also allocated to IMPLAN Sector 429.

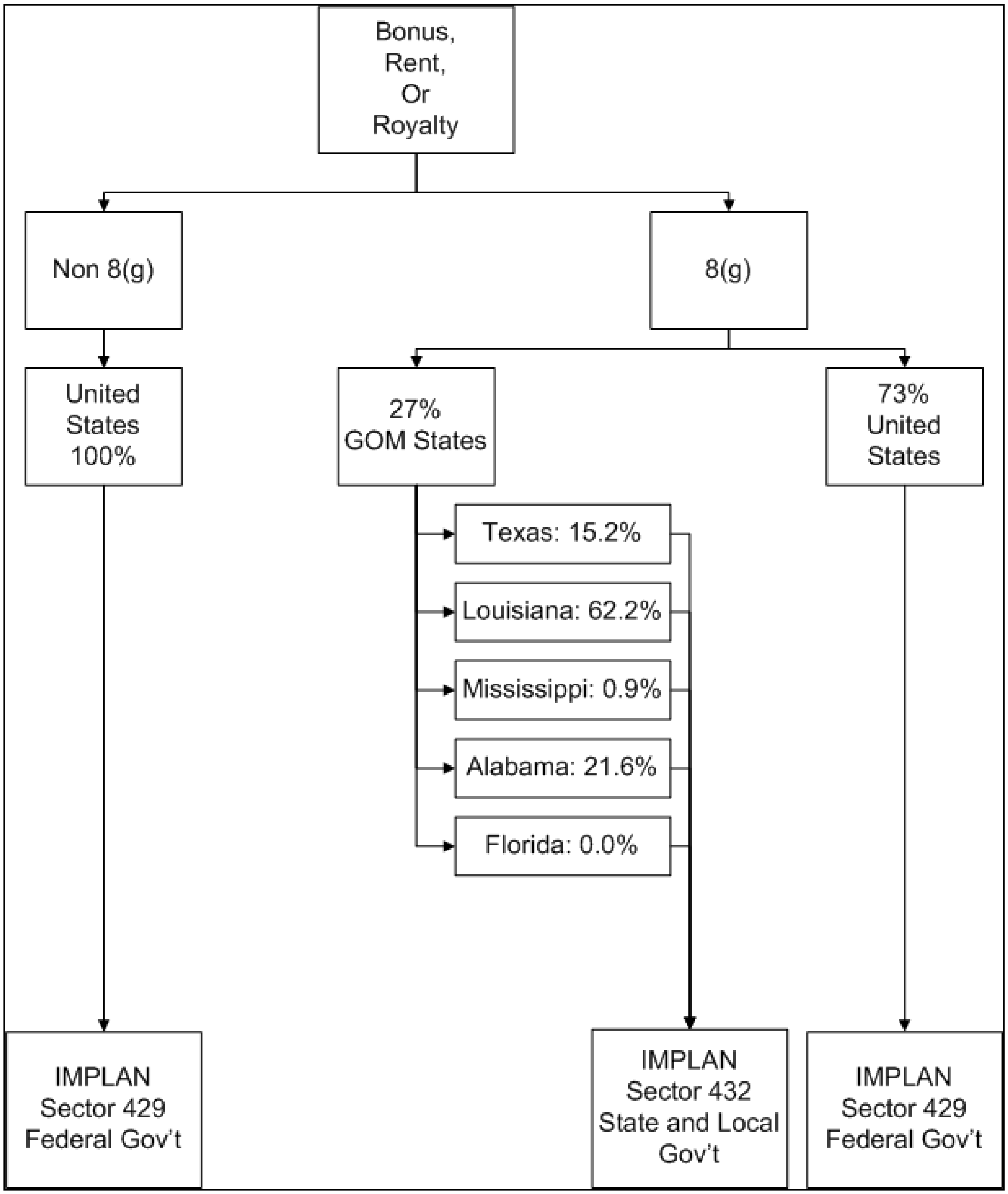

Figure 6. Revenue function logic flow.

Table 51

8(g) Funds Disbursed by Fiscal Year and State

State	FY 2010			
	Disbursed	GOMESA	8(g)	Percent
Texas	$4,211,242	$243,045	$3,968,197	11.6%
Louisiana	$23,305,187	$699,757	$22,605,430	66.2%
Mississippi	$859,244	$589,825	$269,419	0.8%
Alabama	$7,951,467	$651,166	$7,300,301	21.4%
Florida	$1,489	$0	$1,489	0.0%
Total	$36,328,629	$2,183,793	$34,144,836	100.0%
	FY 2009			
	Disbursed	GOMESA	8(g)	Percent
Texas	$8,289,335	$2,159,399	$6,129,936	16.2%
Louisiana	$28,664,551	$6,347,321	$22,317,230	59.2%
Mississippi	$5,957,620	$5,506,235	$451,385	1.2%
Alabama	$15,008,729	$6,179,076	$8,829,653	23.4%
Florida	$1,376	$0	$1,376	0.0%
Total	$57,921,611	$20,192,031	$37,729,580	100.0%
	FY 2008			
	Disbursed	GOMESA	8(g)	Percent
Texas	$13,346,657	$0	$13,346,657	17.9%
Louisiana	$45,763,396	$0	$45,763,396	61.3%
Mississippi	$564,068	$0	$564,068	0.8%
Alabama	$14,990,923	$0	$14,990,923	20.1%
Florida	$83	$0	$83	0.0%
Total	$74,665,127	$0	$74,665,127	100.0%

Source: USDOI ONRR 2011

Table 52

Average 8(g) Funds Disbursed by State

	FY2010	FY2009	FY2008	Average	8(g) Fraction
Texas	11.6%	16.2%	17.9%	15.2%	4.1%
Louisiana	66.2%	59.2%	61.3%	62.2%	16.8%
Mississippi	0.8%	1.2%	0.8%	0.9%	0.2%
Alabama	21.4%	23.4%	20.1%	21.6%	5.8%
Florida	0.0%	0.0%	0.0%	0.0%	0.0%
Total State	100.0%	100.0%	100.0%	100.0%	27.0%
Federal					73.0%
Total 8(g)					100.0%

Source: ERG estimates based on date in Table 51.

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APPENDIX A. OFFSHORE PIPELINE CONSTRUCTION COSTS

When BOEM develops the exploration and development (E&D) scenarios for lease sales, Five-Year Programs, and other studies, the staff estimates the new pipeline miles needed to transport the additional forecasted production. An E&D scenario projects the number of pipeline miles to be constructed each year. Pipeline construction costs might vary by water depth, particularly if the pipeline is on the slope or in the deepwater region.

Section A.1 describes the dataset used to estimate the costs while Section A.2 summarizes the cost estimates.

A.1 DATA SOURCES

Gaul (2009) examined the capability added to the U.S. natural gas pipeline system during 2008. The report references the Natural Gas Pipeline Project Database developed by the U.S. Department of Energy (USDOE) Energy Information Administration (EIA). The database has several key features pertaining to this project. First, offshore Gulf of Mexico (GOM) pipelines can be identified through a "GM" entry for either the beginning region or the end region (two variables in the database). Second, the database contains the in-service year, the cost in millions of dollars, and the number of miles. With the understanding that the figures reflected the projected cost and not necessarily the actual final cost (USDOE EIA 2010), ERG requested, and USDOE EIA supplied, a copy of the database. The rest of the data and analysis presented in this appendix is done so with this understanding.[30]

ERG identified 12 natural gas pipeline projects that were carried out in the offshore GOM region since 2005 and had complete data. Table A-1 presents the project name, in-service year, cost in millions of dollars, and miles for each pipeline project.

The Natural Gas Pipeline Project Database did not record the water depth for each project. ERG used several approaches to obtain this information. Some water depths are taken from project descriptions. For others, ERG identified the Outer Continental Shelf (OCS) block in which the production structure was located and then found the water depth in that block. Table A-2 displays the source and the water depth in feet for each project.

A.2 COST ESTIMATES

ERG converted all costs into 2008$ using the Consumer Price Index (CPI) (USDOL BLS 2010). In cases where the project has a future date, ERG assumed that the cost corresponded to the most recent year in the database (i.e., 2010). Using the converted figures, ERG calculated the cost per mile for each project and averaged the cost per mile within each water depth range (see Table A-3).

30 ERG did not identify any other data source with more complete cost data where offshore wells could be specifically extracted for analysis.

Table A-1

Offshore GOM Pipeline Projects Since 2005

Project Number	Project Name	Year	Cost (Million$)	Miles
1	Energy Bridge Connection Line	2005	5	8
2	Tenneco Triple-T Extension	2007	22	6.23
3	MPEH Pipeline Project	2012	120	97
4	Cleopatra Gathering System Phase 2	2007	36	21
5	Enbridge Shenzi Lateral	2007	65	11
6	Enterprise Constitution Gathering Pipeline	2006	48	32
7	Okeanos Thunder Horse Segment	2006	50	26
8	Enbridge Neptune Deepwater Project	2008	50	29
9	WFS Blind Faith Extension	2008	255	71
10	Walker Ridge Gathering	2011	500	190
11	Enterprise Independence Trails Offshore Line	2006	209	140
12	Perdido Norte Projects	2010	250	184

Source: USDOE EIA 2010

Table A-2

Pipeline Project Water Depths

Project Number	Project Name	Water Depth (ft)	Source
1	Energy Bridge Connection Line	300	Offshore Magazine 2005
2	Tenneco Triple-T Extension	415	USDOI BOEMRE 2010
3	MPEH Pipeline Project	210	Red Orbit 2005
4	Cleopatra Gathering System Phase 2	4000	Sauer and Wiseman 2006
5	Enbridge Shenzi Lateral	4300	Rigzone 2006
6	Enterprise Constitution Gathering Pipeline	5128	SubseaIQ 2010
7	Okeanos Thunder Horse Segment	6000	Offshore-Technology 2010a
8	Enbridge Neptune Deepwater Project	4221	Antani, et al. 2008
9	WFS Blind Faith Extension	7000	Williams 2010
10	Walker Ridge Gathering	7000	Rigzone 2009
11	Enterprise Independence Trails Offshore Line	8000	Offshore-Technology 2010b
12	Perdido Norte Projects	8000	Tyson 2007

Table A-3

Offshore Pipeline Projects From 2005

Project Name	Year	Cost (Million$)	Cost (Millions, 2008$)	Miles	Water Depth (ft)	Water Depth (m)	Water Depth Range	Cost (Millions, 2008$/Mile)	Average Cost (Millions, 2008$/Mile by Water Depth)
Energy Bridge Connection Line	2005	$5	$5.51	8	300	91.44	60–200	$0.69	$1.32
Tenneco Triple-T Extension	2007	$22	$22.84	6.23	415	126.49	60–200	$3.67	$1.32
MPEH Pipeline Project	2012	$120	$118.59	97	210	64.01	60–200	$1.22	$1.32
Cleopatra Gathering System Phase 2	2007	$36	$37.38	21	4000	1219.20	800–1,600	$1.78	$2.33
Enbridge Shenzi Lateral	2007	$65	$67.50	11	4300	1310.64	800–1,600	$6.14	$2.33
Enterprise Constitution Gathering Pipeline	2006	$48	$51.26	32	5128	1563.01	800–1,600	$1.60	$2.33
Okeanos Thunder Horse Segment	2006	$50	$53.40	26	6000	1828.80	800–1,600	$2.05	$2.33
Enbridge Neptune Deepwater Project	2008	$50	$50.00	29	4221	1286.56	1,600–2,400	$1.72	$2.76
WFS Blind Faith Extension	2008	$255	$255.00	71	7000	2133.60	1,600–2,400	$3.59	$2.76
Walker Ridge Gathering	2011	$500	$494.11	190	7000	2133.60	1,600–2,400	$2.60	$2.76
Enterprise Independence Trails Offshore Line	2006	$290	$309.71	140	8000	2438.40	2,400+	$2.21	$1.72
Perdido Norte Projects	2010	$250	$247.06	184	8000	2438.40	2,400+	$1.34	$1.72

Source: USDOE EIA 2010, calculated by ERG

The Enbridge Shenzi Lateral project is an outlier with a cost of $6.14 million per mile, nearly twice that of the next most expensive pipeline. ERG recalculated the average cost per mile by water depth without the Shenzi project, see Table A-4. There were no projects in the 0–200 foot or 650–2,600 foot ranges (0–60, 200–800 m).

Table A-4

Average Cost Per Mile (Millions, 2008$) by Depth Range

Water Depth (ft)	Water Depth (m)	Average Cost Per Mile (Millions, 2008$)
0–200	0–60	n/a
200–650	60–200	$1.32
650–1,300	200–400	n/a
1,300–2,600	400–800	n/a
2,600–5,200	800–1,600	$1.80[a]
5,200–8,000	1,600–2,400	$2.76
8,000+	2,400+	$1.72

[a] This average fell from 2.33 in Table A-3 after the Shenzi project was excluded.

Source: Calculated by ERG

ERG used regression analysis to estimate average costs per mile for the water depth ranges in which no projects were identified. ERG estimated a linear relationship between water depths and construction costs per mile using 11 data points taken from the projects listed in Table A-2, excluding the Shenzi outlier. ERG then used the midpoint of each water depth (m) range to estimate an average construction cost for that range. The equation describing the relationship is:

Cost per Mile ($ thousand) = $1,751 + (0.21)*Water Depth (m)

Table A-5 presents the estimates based on this relationship.

Table A-5

Estimated Cost Per Mile by Water Depth (Thousands, 2008$)

Water Depth Range (m)	Water Depth Midpoint (m)	Line Est. Cost Per Mile ($ Thousand)
0–60	30	$1,760
60–200	130	$1,780
200–400	300	$1,810
400–800	600	$1,880
800–1,600	1,200	$2,000
1,600–2,400	2,000	$2,170
2,400+	3,000	$2,380

Source: ERG estimates

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APPENDIX B. STRUCTURE DECOMMISSIONING COSTS

On October 15, 2010, BOEMRE (now BOEM) issued a Notice to Lessees and Operators (NTL) with guidance on decommissioning wells and structures (USDOI BOEMRE 2010). In particular, the definition of when decommissioning takes place changes from one year after a lease terminates (i.e., a lease basis) to when a well or platform stops production for 5 years or more (i.e., a well and structure basis). Kaiser (2010) estimates that there are nearly 5,200 wells that meet the new definition for decommissioning. Presumably, a proportionate number of structures to which those wells are attached also would need to be decommissioned.

Section B.1 describes the data sources used in this analysis. Section B.2 presents the estimated costs for decommissioning production structures in the GOM and compares them with decommissioning costs estimated for production structures in the Pacific OCS region. Section B.3 describes of the cost items included in the estimates. Section B.4 reviews the assumptions and methodology used to arrive at the estimated costs.

B.1 DATA SOURCES

Kaiser et al. (2009a,b) provides information on actual decommissioning costs for platforms in the GOM from 2003 to 2008 in water depths ranging from 0 to approximately 90+ m (300+ ft). Proserv Offshore (2009) provides engineering estimates, based on representative platforms and structures in water depths ranging from 400 to 8,000 feet (approximately 120 m to over 2,400 m). The latter report also focuses strictly on GOM structures. These two reports form the basis of the updated decommissioning costs in MAG-PLAN.

B.2 DECOMMISSIONING COST ESTIMATES

B.2.1 Cost Estimates

Table B-1 presents the costs of decommissioning platforms and other structures in the GOM. These costs were derived from Proserv (2009) and Kaiser et al. (2009a, b). Costs are presented for the platform/structure types currently found in the GOM:

- Fixed platforms (including compliant towers)
- Spars
- Mini-tension leg platforms (mini-TLPs)
- TLPs
- Semisubmersibles

Table B-1

Cost of Platform/Structure Decommissioning in the GOM by Water Depth (Thousands, 2008$)

Water Depth		Assumed Type of Platform/Structure[a]	With Explosives	Without Explosives
Meters	Feet			
0–60	0–200	Fixed Platform	$1,528	$1,757
60–200	200–650	Fixed Platform	$4,445	$5,111
200–400	650–1,300	Fixed Platform	NA	$40,525
400–800	1,300–2,600	Mini-TLP/Spar/Fixed Platform	NA	$45,198
800–1,600	2,600–5,200	Semisubmersible/TLP/Spar	NA	$25,133
1,600–2,400	5,200–8,000	Semisubmersible/Spar	NA	$24,973
,2400+	8,000+	Semisubmersible	NA	$16,692

[a] In 400–800 m depths, ERG assumed: 33 percent of platforms/structures are spars; 33 percent are mini-TLPs; and 33 percent are fixed platforms represented by Bullwinkle at 400 m. In 800–1,600 m depths, ERG assumed: 4 percent are semisubmersibles, 46 percent are spars, 33 percent are TLPs, and 17 percent are mini-TLPs. In 1,600–2,400 m depths, ERG assumed: 44 percent are spars and 56 percent are semisubmersibles (based on information collected by Proserv 2009).

Source: Kaiser et al. 2009a,b; Proserv 2009

Note that decommissioning with explosives is less expensive than decommissioning without explosives; however, decommissioning costs with explosives were available only for water depths up to 200 meters. The most expensive types of structures to decommission are those in water depths ranging from 200 to 800 meters (i.e., TLPs, mini-TLPs, spars, and fixed platforms). Floating production structures, such as semisubmersibles, are two to three times less expensive to decommission.

The costs range from $1.5 million to $5.1 million for water depths up to 200 meters. For water depths between 200 meters and 800 meters, decommissioning costs range from $40.5 million to $45.2 million. For water depths beyond 800 meters, the costs drop to between $16.7 million and $25.1 million.

Table B-2 presents the estimated costs for decommissioning production structures in the Pacific OCS, taken from Proserv Offshore (2010). The costs vary by water depth and weight and range from $12.0 million to $155.9 million. The cost assumptions include the need to import derrick barges from the GOM while excluding the use of explosives, thus leading to the higher costs.

Table B-2

Estimated Costs for Decommissioning Platforms in the Pacific OCS

Platform	Decommissioning Cost	Water Depth (ft)	Estimated Removal Weight (tons)	Year Installed
Gina	$12,022,672	95	1,006	1980
Hogan	$34,453,019	154	3,672	1967
Edith	$29,178,537	161	8,038	1983
Houchin	$33,027,029	163	4,227	1968
Henry	$18,621,649	173	2,832	1979
PlatformA	$25,595,019	188	3,457	1968
PlatformB	$30,548,957	190	3,457	1968
Hillhouse	$26,025,227	190	3,100	1969
PlatformC	$23,683,643	192	3,457	1977
Gilda	$42,788,799	205	8,042	1981
Irene	$32,645,792	242	7,100	1985
Elly	$21,360,859	255	9,400	1980
Ellen	$35,919,110	265	9,600	1980
Habitat	$28,653,889	290	7,564	1981
Grace	$41,645,339	318	8,390	1979
Hidalgo	$67,918,547	430	21,050	1986
Hermosa	$80,351,462	603	27,330	1985
Harvest	$88,278,478	675	29,040	1985
Eureka	$94,234,596	700	29,000	1984
Gail	$88,839,896	739	29,993	1987
Hondo	$91,690,506	842	23,550	1976
Heritage	$149,600,043	1,075	56,196	1989
Harmony	$155,913,807	1,198	65,089	1989

Source: Proserv 2010

B.2.2 Year of Cost Estimates

All costs in Table B-1 are representative of 2008 costs. Although Proserv's report is dated October 2009, ERG assumed that the costs were gathered primarily during 2008 and early 2009. The Kaiser et al. (2009a,b) reports provide costs only on a nominal basis covering the years 2003 through 2008. These costs could not be disaggregated by year; however, ERG used additional information to approximate costs in 2008$ for these shallow-water platforms. In addition to the average costs of platform removals, the report also indicates the number of platforms removed by year. The median platform-year is 2006 (that is, roughly half of the platforms reported were decommissioned prior to 2006 and half after 2006); therefore, ERG assumed that all costs were in 2006 dollars. Proserv (2009) estimated a decommissioning price index for the GOM over the years of interest with an inflation factor of approximately 16 percent for the 2006 to 2008 period.

ERG used this index to convert the costs presented in Kaiser et al. (2009a,b) from 2006$ to 2008$.

B.3 COST ITEMS INCLUDED IN ESTIMATES

The costs of platform/structure decommissioning are organized to include the costs of:

- Platform preparation, which includes flushing hydrocarbons from lines; cutting deck equipment to be removed; and cutting electrical, tubing, and piping connections.
- Structure removal and towing, including severing of tendons, cables, chains, and piles.
- Site clearance, which includes checking the site for removal completeness (e.g., searching for and clearing any remaining debris).

To the extent possible, the costs do not include those for:

- Plugging and abandoning wells.
- Decommissioning pipelines.
- Disposal of platforms and structures onshore.

ERG could not ensure that the platform removal costs reported by Kaiser et al. (2009a,b) excluded disposal costs. However, nearly all platforms discussed in the article were reefed (i.e., left in place below the water line, toppled, or towed and dropped into shallow water for use as artificial reefs). Thus, the costs for fixed-platform removal reported by Kaiser et al. (2009a,b) are unlikely to include many costs attributable to onshore disposal. For the most part, costs for structures estimated by Proserv (2009) did not include any onshore disposal costs and, in the instances in which they did, ERG removed them when making estimates.

For fixed platforms, costs included those for removal of conductors. Costs for removing conductors were divided between conductor removals using explosives and conductor removals using abrasion. ERG assumes explosives are not used below 200 m (650 ft), based on the fact that Proserv (2009) did not estimate costs for explosive removal of conductors for any fixed platforms below this depth.

For other deepwater structures (spars, mini-TLPs, TLPs, and semisubmersibles), Proserv (2009) included the costs of conductor removal with the costs of plugging and abandoning (P&A) wells. The costs for conductor removal were not separable from P&A costs. We assume that Proserv did this because the conductor removal activity is best done at the time wells associated with these deepwater structures are abandoned, and these costs are not normally incurred at the time of removal of these tethered structures.

B.4 KEY ASSUMPTIONS

The following sections provide information on the sources used and the assumptions made for each type of platform/structure at each depth. The assumptions about which structures are present at each depth rely on information from Proserv (2009), which provides data by type and by depth for all structures in the GOM in water deeper than 400 ft (approximately 120 m). ERG used these data to provide the structure-type breakout by depth shown in Table B-1.

B.4.1 Fixed Platforms

B.4.1.1 Fixed Platforms (0 to 60 m)

ERG derived costs for fixed platforms in this depth range from Kaiser et al. (2009a,b) using average platform preparation and removal costs for platforms in the 0 to 100 ft and 100 to 200 ft depth ranges (0 to 60 m combined). ERG approximated costs for explosive and abrasive removal of conductors using information from Proserv (2009). The Proserv study determined that when explosives are used, the total removal costs for a fixed platform (including preparation costs) are 15 percent lower than those incurred when abrasive techniques are used (see Proserv 2009, Table 4.3). To derive the cost difference, ERG assumed that 80 percent of conductors at platforms in the 0 to 60 m depth range are removed using explosives. To calculate the average cost of explosive removal, ERG applied this assumption to the overall average platform preparation and removal costs. After calculating the average platform removal cost under an explosive removal scenario, ERG multiplied this estimate by 1.15 to estimate platform removal costs under a nonexplosive removal scenario. As Table B-1 shows, the costs of decommissioning fixed platforms in the GOM in 0 to 60 m water depth are estimated to be $1.5 million when explosives are used and $1.8 million when abrasive techniques are used.

B.4.1.2 Fixed Platforms (60 to 200 m)

Kaiser et al. (2009a,b) also provides information on fixed platform costs for platforms in depths from 60 to roughly 90 m. Proserv's (2009) study provides information on fixed platform costs from about 120 to 200 m. ERG used both of these sources to derive the average cost of platform removal in the 60 to 200 m water depth range.

The first step was to identify average costs for explosive and abrasive removal of platforms. Proserv (2009) provided information on nine platforms in this depth range that allowed us to distinguish between platforms where explosive methods were implemented (five) and those where abrasive removal techniques were implemented (four). Proserv estimates that the cost of explosive removal techniques is 15 percent lower than the cost of abrasive removal techniques. ERG calculated the alternative scenario for each of the nine platforms using this estimate. Where the Proserv report estimated costs assuming the use of explosives, ERG multiplied the platform removal costs by 1.15 to approximate the costs of a nonexplosive removal scenario. Where the report assumed abrasive techniques were used, ERG divided the platform removal costs by 1.15 to approximate costs under an explosive removal scenario. With that, ERG calculated the average cost of platform removal under each scenario in the 120 to 200 m water depth range.

To separate costs in Kaiser et al. (2009a,b) by explosive versus nonexplosive removals, ERG used the average costs for platform preparation and removal in the 200 to 300+ ft range (60 to 90+ m) and the same method described in Section B.4.1.1 for calculating such costs in the 0 to 60 m water depth range.

ERG assumed that within the 60 to 200 m water depth range, 80 percent of all structures would be fixed platforms in the 60 to 100 m water depth range. Thus, only 20 percent of structures would be in the 100 to 200 m range. Under this assumption ERG created a weighted average cost for both explosive and nonexplosive removal using the average costs derived using Kaiser et al. (2009a,b) (80 percent) and the average costs derived using Proserv (2009) (20 percent). As Table B-1 shows, costs for platform decommissioning in this depth range are expected to average $4.4 million (explosive removal) and $5.1 million (abrasive removal).

B.4.1.3 Fixed Platforms (200 to 400 m)

Only Proserv (2009) provides information on the cost of removing platforms at depths of 200 to 400 meters. According to its information, only fixed platforms (and one compliant tower) are currently used in this depth range. Proserv assumed no platforms in this depth range use explosives; therefore, we do not calculate an alternative scenario.

The average cost reported in Table B-1 for fixed platforms in the 200 to 400 m depth range is $40.5 million. The cost is derived through a simple average of all the estimated costs of the representative platforms selected by Proserv at these depths. As the table indicates, the cost of platform decommissioning rises dramatically for fixed platforms in water depths greater than 200 m.

B.4.2. Deepwater Structures (400 to 2,400+ m)

B.4.2.1 General Assumptions

In water depths greater than 400 m, fixed platforms are rare. The three structures (two of which are compliant towers) are represented by costs estimated in the Proserv report for one fixed platform in 400 m water depth. All of these fixed structures are in 400 to 800 m water depths.

Costs for all other deepwater structures (divided into spars, mini-TLPs, TLPs, and semisubmersibles) are tailored to each assumed water depth. Proserv provides only one depth assumption for each structure, but it also provides scaling values that can be used to modify costs depending on the depth. Depth is a major cost driver in all of the deepwater structures (except fixed platforms) because it defines the length of the chain/mooring lines/tendons used to attach these structures to the seafloor. The longer these are, the more difficult and time consuming their removal. Other costs are less depth sensitive.

Proserv provides information for each deepwater GOM structure, including type of structure, number of tethers (i.e., mooring chains and lines or tendons), deck weight, and water depth.[31] ERG's assumptions on typical water depths, number of tendons by water depth range, and type of structure are discussed below in Section B.4.2.3.

B.4.2.2 Specific Assumptions by Water Depth

In the 400 to 800 m water depth range, Proserv indicates that there are three fixed platforms (two of which are compliant towers), three spars, two mini-TLPs, one TLP, and one semisubmersible. ERG extrapolated an overall average cost at this depth range by using the estimates for the average costs for three types of structures. ERG assumed that 33 percent of

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31 ERG found some issues in the Proserv report. The costs on a per line per ft water-depth basis for line removal appeared to include mooring chain removal costs, even though mooring chain costs per line per ft water depth were reported separately. ERG recalculated the costs per line per ft water depth for mooring line removal only and used both costs separately. Additionally, ERG determined that various contingency costs were not being applied consistently, and no reason was indicated for the differences in application. For example, nearly all mobilization and demobilization costs for barges and tugs across all types of structures were assigned no weather or work contingencies, but for semisubmersibles, contingencies were applied to barges and tug mobilization and demobilization costs. As another example, in nearly all cost estimates, weather contingencies were calculated at 20 percent of costs. However, for site clearance costs for two types of structures, the contingency was calculated at 10 percent rather than 20 percent, even though in one case the line item was labeled 20 percent. ERG corrected the contingency cost where it believed a contingency was incorrect or incorrectly applied. However, these changes resulted in cost differences that were not substantial.

structures are fixed platforms, 33 percent are mini-TLPs (costs for mini-TLPs and TLPs at this depth should be similar according to information in Proserv's report), and 33 percent are spars (the cost for one semisubmersible at this depth should have little impact on overall average costs). The overall average decommissioning cost for this depth range, shown in Table B-1, is estimated to be $45.2 million per structure, primarily due to the relatively high cost of removing fixed platforms. As the table shows, however, despite the substantial increase in depth, average decommissioning costs are not much higher than the average decommissioning costs in the 200 to 400 m water depth range.

In the 800 to 1,600 m water depth range, Proserv indicates that there are four mini-TLPs, eight TLPs, 11 spars, and one semisubmersible. ERG calculates an overall average cost for this depth range based on each structure type's proportion of the total structures found in the depth range, again, based on the information in Proserv's (2009) report (see footnotes to Table B-1). ERG uses this same approach in the 1,600 to 2,400 m water depth range, where Proserv reports that four spars and five semisubmersibles are operating. Only one semisubmersible operates in the 2,400+ range.

As Table B-1 shows, average decommissioning costs actually decline at greater depths because fewer spars and more TLPs and semisubmersibles (which are much less expensive to decommission) are installed. In 800 to 1,600 m water depths, average costs are $25.1 million per structure, and in 1,600 to 2,400 m water depths, average costs are $25.0 million per structure. In the 2,400+ m water depth range, average costs decline even more noticeably. ERG estimated that the average cost at this depth, assuming only semisubmersibles operate there, was only $16.7 million per structure for decommissioning.

B.4.2.3 Specific Assumptions by Structure Type

Other structure-specific assumptions worth noting include:

Spars: Two cost estimates are available from Proserv (2009) for deck removal, depending on deck weight (greater than or less than 5,000 short tons [st]). ERG assumed that the deck weight was greater than 5,000 st for all spars, based on data provided by Proserv (2009) showing few spars with deck weights below 5,000 st. To adjust costs for water depths, ERG made the following assumptions based on the Proserv structure data:

- 400 to 800 m water depth: ERG assumed 12 mooring lines and a 2,500 ft (750 m) water depth.
- 800 to 1,600 m water depth: ERG assumed 12 mooring lines and a 4,000 ft (1,200 m) water depth.
- 1,600 to 2,400 m water depth: ERG assumed nine mooring lines and a 6,000 ft (1,800 m) water depth.

Mini-TLPs: Two cost estimates are available for deck removal on mini-TLPs as well. ERG assumed that the deck weighs less than 5,000 st for mini-TLPs in the 400 to 800 m water depth range. In the 800 to 1,000 m water depth range, however, deck weights were split evenly. ERG used the average of costs estimated by Proserv for decks weighing less than 5,000 st and those for decks weighing more than 5,000 st to represent the split between deck weights in this water depth range. In addition, ERG scaled platform preparation costs at the Proserv-suggested cost of $108 per deck-ton, using 3,000 st and 5,000 st as the average for mini-TLPs in 400 to 800 m and

800 to 1,600 m water depths, respectively. To adjust costs for water depths, ERG made the following assumptions based on Proserv's structure data:

- 400 to 800 m water depth range: ERG assumed six tendons at 1,700 ft (520 m) water depth
- 800 to 1,600 m water depth range: ERG assumed six tendons at 2,900 ft (880 m) water depth

TLPs: ERG used TLP costs only for such structures in the 800 to 1,600 m depth. For the estimate in Table B-1, ERG used the costs Proserv derived for the representative structure at this depth (with some minor corrections to contingencies).

Semisubmersibles: ERG estimated average costs for semisubmersibles in 1,600 to 2,400 m water depth and 2,400+ water depth. To adjust costs for water depths, ERG made the following assumptions based on Proserv's structure data:

- 1,600 to 2,400 m water depth: ERG used the costs Proserv developed for their selected representative semisubmersible with 16 mooring lines in 6,000 ft (1,800 m) water depth.
- 2,400+ m water depth: ERG assumed 16 mooring lines and a 9,200 ft (2,800 m) water depth.

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APPENDIX C. FPSO AND SUBSEA SYSTEM COSTS

MAG-PLAN allocates activity functions to IMPLAN industry sectors (See Section 2.3). One of the new activity functions added to MAG-PLAN 2012 is the installation of a FPSO (floating production, storage, and offloading) vessel and associated subsea system (Figure C-1). Sections C.1 and C.2 develop "typical costs" for a subsea system and FPSO, respectively, based on public data, for the purpose of splitting the costs between IMPLAN sectors 209 (Shipbuilding and repairing) and 206 (Mining and oil and gas field machinery).[32]

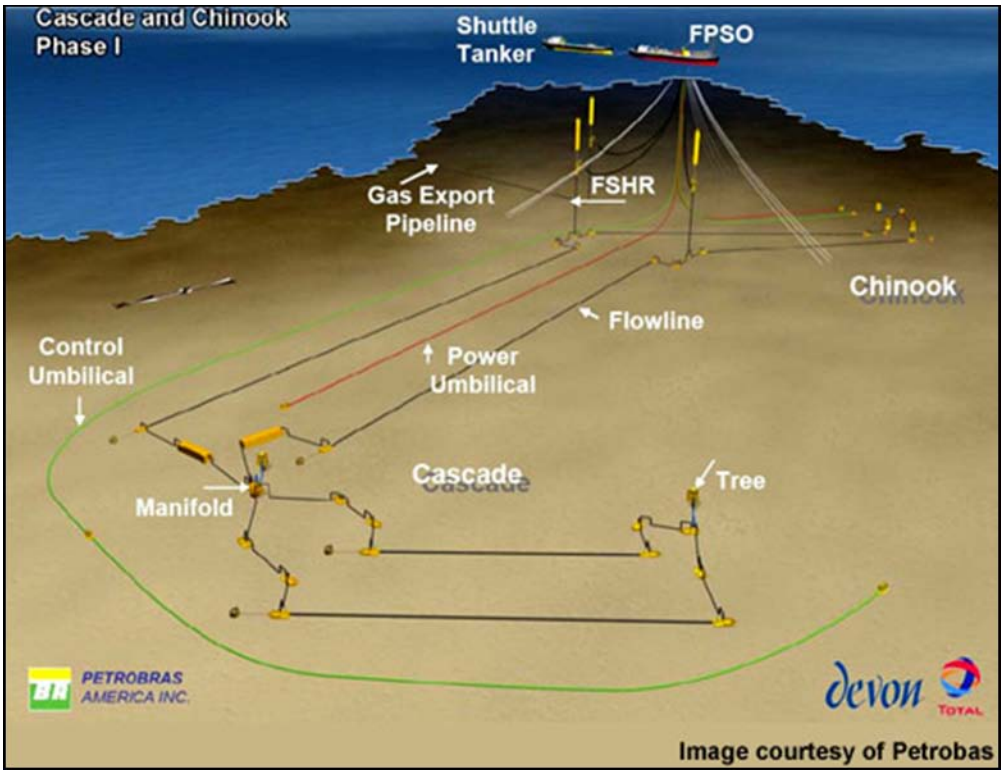


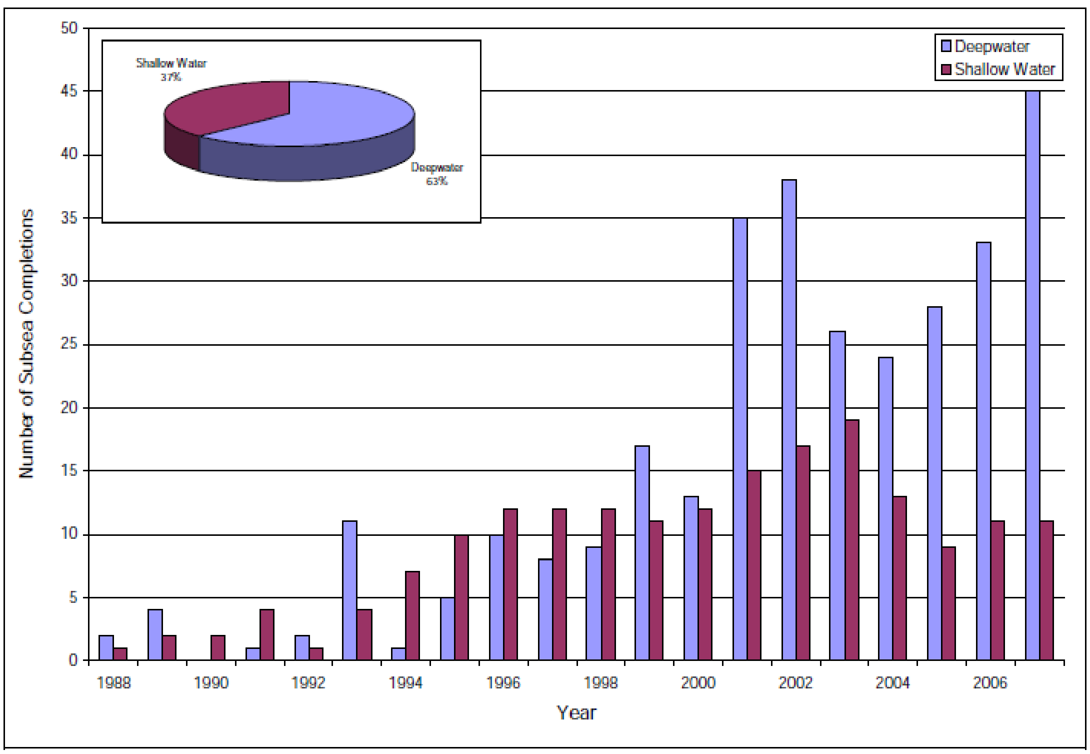
Figure C-1. Cascade and Chinook Fields with subsea completions and FPSO.

[32] The costs presented in Chapter 3 reflect a mix of possible floating production systems, while this appendix examines those for only the FPSO vessel. In keeping with the "no gap, no overlap" approach for costing, the values presented in Chapter 3 include the floating system and associated subsea components.

C.1 Subsea Tiebacks/Well Completions

C.1.1 Description

Subsea systems have one or more of the following components: subsea wells, manifolds, control umbilicals, pumping/processing equipment, and flow lines (USDOI MMS 2008). Figure C-1 shows the layout of Petrobras' Cascade and Chinook fields with these different components. FSHR stands for "free standing hybrid riser," where a steel pipe is supported by a near-surface buoyancy can (yellow in Figure C-1) and is connected to a flexible flow line to the FPSO (Technip n.d.). The surface part of a subsea system includes the control system and other production equipment (USDOI MMS 2008). USDOI MMS (2008) notes that, before 1993, fewer than 10 subsea completions per year were performed. The number jumped in 2001 and 2002 as the fields supplying the Na KiKa semisubmersible were drilled. The annual number of subsea completions took another jump in 2007, when Independence Hub went into operation (see Figure C-2).



Source: USDOI MMS 2008

Figure C-2. Number of subsea completions per year.

C.1.2 TYPICAL COSTS

USDOI MMS (2008) reports that 85 percent of all currently active deepwater fields use subsea systems, thus implying that project costs likely include subsea completion costs. To provide another estimate of "typical" costs, ERG examined the major suppliers. Five companies dominate the subsea production equipment market: Aker Solutions, Cameron International, Dril-Quip, FMC, and Vetco Gray (General Electric Oil and Gas) (Kopits and Jones 2010). Between 2007 and 2009, FMC held approximately 45 to 47 percent of the market, Cameron and Vetco Gray held about 17 to 16 percent each, Aker Solutions garnered 13 percent, and Dril-Quip held the remaining 7 percent (Kopits and Jones 2010). ERG examined the press releases for each company from January 2009 through May 2010 for contract awards for subseabed equipment. These are listed in Table C-1. The announced contracts range from $11 million to $700 million, with an average value of $150 million and a third quartile value of $208 million (i.e., 75 percentile in the distribution). Most of the orders for subsea production equipment during the 2009 to mid-2010 period are for regions other than the GOM, but given the wide range of regions included in Table C-1, equipment costs for the GOM are likely to be in the same range. Because a subsea system might be completed with components from more than one vendor, ERG proposes to use $200 million (2008$) (i.e., the third quartile value in Table C-1) as a reasonable estimate for the cost of a subsea system. For comparison, the subsea system for the Chinook and Cascade fields costs approximately $200 million (FMC 2007).

C.2 FPSOs

C.2.1 DESCRIPTION

A FPSO is a ship-like vessel (sometimes a converted tanker) moored at an offshore oil and gas field (Figure C-3). The vessel is equipped to receive, process, store, and offload hydrocarbons. Converting a tanker into a FPSO involves adding processing equipment and accommodations. The cargo capacity serves as storage for the treated product until it is transferred to shuttle tankers for transport to the shore. FPSOs operate in locations where the expense of adding subsea pipelines and/or onshore processing capabilities would make the field unprofitable due to the high cost of adding such capabilities.

Figure C-3. FPSO.
Source: Wilhoit and Supan. 2009 SBM Offshore

C.2.2 TYPICAL COSTS

Wilhoit and Supan (2009) list 105 vessels owned by contractors such as BW Offshore or SBM Offshore and 92 operator-owned vessels. For this study, ERG focused on the six vessels operating along the East Coast of Canada, the United States, and Mexico (including the GOM). These are listed in Table C-2. ERG could not find cost information for the three PEMEX vessels. The cost of converting an existing vessel to a FPSO (e.g., Pioneer) is approximately $740 million. New vessels range from $1.6 billion to $2.35 billion Canadian ($1.18 billion to $1.95 billion U.S. at the 1996 and 2005 exchange rates, respectively).

Table C-1

Orders for Subsea Tiebacks and Completions (January 2009 through May 2010)

Company	Year	Region	Cost (Millions, US$)	Number of Items Included												
				Riser	Subsea boosting systems	ESDV (emergency valve)	Umbilicals	Subsea power cables	Topside subsea control system	Tie-in and connection system	Subsea trees	Manifold	Subsea wellheads	Surface trees	Surface wellheads	Subsea separation module
Aker	2009	Korea	$37	1												
Aker	2009	Brazil	$37		8	1										
Aker	2009	North Sea	$50						9		9					
Aker	2009	Norwegian Sea	$58				28 km		3		3	1	3			
Aker	2009	North Sea	$75				24 km			1		1				
Aker	2009	Barents	$382				20 km		24	1	24	8				
Aker	2010	Mediterranean	$20				12 km	8 km	1	1						
Aker	2010	Brazil	$254								61					
Aker	2010	Australia	$91				264 km									
Aker	2010	Mediterranean	$108				240 km									
Cameron	2009	Gulf of Mexico	$100						1	1	4	1				
Cameron	2009	Brazil	$500								138					
Cameron	2009	Gulf of Mexico	$86		16											
Cameron	2010	Gulf of Mexico	$230						1	>1	12	4				
Dril-Quip	2009	Gulf of Mexico	$80										yes			
Dril-Quip	2009	Brazil	$180										yes			

Table C-1.

Orders for Subsea Tiebacks and Completions (January 2009 through May 2010) (continued)

Company	Year	Region	Cost (Millions, US)	Number of Items Included: Riser	Subsea boosting systems	ESDV (emergency valve)	Umbilicals	Subsea power cables	Topside subsea control system	Tie-in and connection system	Subsea trees	Manifold	Subsea wellheads	Surface trees	Surface wellheads	Subsea separation module
FMC	2007	Gulf of Mexico	$200		2				1		4	3				
FMC	2009	Brazil	$30											30	30	
FMC	2009	Timor	$60				yes		3		3					
FMC	2009	North Sea	$73						8	8	8					
FMC	2009	Brazil	$90													1
FMC	2009	Gulf of Mexico	$82						1		9					
FMC	2009	Angola	$80				yes		1	1	6		6			
FMC	2009	Brazil	$75						2		12	4				
FMC	2009	Ghana	$210	2							19	8				
FMC	2009	Angola	$140									3				
FMC	2010	North Sea	$40	10						10						
FMC	2010	Angola	$65							yes	yes					
FMC	2010	Norwegian	$62						2		2	1				
FMC	2010	North Sea	$210						10		9	2	8			
FMC	2010	Brazil	$400								<=107					
GE	2009	Brazil	$250										250			
GE	2009	Brazil	$11										4			
GE	2010	Australia	$700				yes		yes		20	5	20			

Sources: Aker 2010a–d and 2009a–f; Cameron 2010 and 2009a–c; Dril-Quip 2009a,b; FMC 2010a–e and 2009a–i; GE 2010 and 2009a,b.

C.2.2.1 Pioneer

Pioneer will be the first FPSO to operate in the GOM OCS in the Cascade and Chinook fields. Petrobras selected BW Offshore, a Bermuda-incorporated Norwegian firm, to convert, install, and operate a FPSO. The contract is for up to eight years with a nominal value of $740 million (BW Offshore 2007, Offshore-Technology 2010). BW Offshore, in turn, selected Keppel Offshore & Marine for the conversion, which was done in Singapore (BW Offshore 2009). ERG is using the value of the lease as a proxy for the value of the vessel.

C.2.2.2 White Rose

Husky Energy is developing the White Rose field, east of St. John's, Canada, with the SeaRose FPSO. Samsung Heavy Industries (South Korea) was responsible for the design, fabrication, commissioning and delivery of the hull, complete with accommodation, helideck, topsides support stools, and turret, while the topsides and installation took place in the Marystown, Newfoundland, shipyard (Ship Technology, 2009). First production was in 2005, and Husky noted that total capital costs for development were about $2.35 billion Canadian ($1.95 billion U.S.). The cost appears to include seven or eight horizontal oil wells, 10 or 11 water injectors, and two (required) gas injectors (Husky 2009).

C.2.2.3 Terra Nova

The Terra Nova field was discovered in 1984 and came into production in 2002. The FPSO was built in a South Korean shipyard (Petro-Canada 1999). ERG found a reference to a preliminary startup capital cost estimate of $1.6 billion Canadian (Newfoundland and Labrador 1996).

C.2.2.4 Bourbon Opale

Wilhoit and Supan (2009) list the Bourbon Opale as new construction. However, the brochure on the Norwegian Bourbon Offshore company Web site lists it as a conversion (Bourbon Offshore n.d.). Beckman (2004) calls Bourbon Opale and Toisa Pisces (see Section 4.2.5) "ecological" well test vessels with fluid storage and processing facilities. The Aker Langsten shipyard in Tomrefjord, Norway, built the original Bourbon Opale and handled the conversion. The topsides were built by The Expro Group in Reading, United Kingdom. The vessel is leased to PEMEX. ERG could not locate conversion cost information.

C.2.2.5. Toisa Pisces

Sealion purchased a cable-laying vessel, converted it into an "ecological" well test vessel, and renamed it the Toisa Pisces. The conversion was done in Gdansk, Poland (Beckman 2004, Sealion n.d.). PEMEX also leases this vessel. ERG could not locate conversion cost information.

Table C-2

FPSOs

Vessel Name	Sea Rose (White Rose)	Terra Nova	Pioneer	Bourbon Opale	Toisa Pisces	Yuum K'ak Na'ab
FPSO Owner	Husky	Suncor Energy (Petro-Canada)	BW Offshore	Bourbon Offshore	Toisa Horizon	BW Offshore
FPSO Operator	Husky	Suncor Energy (Petro-Canada	BW Offshore	Bourbon Offshore	Secunda Marine	BW Offshore
Field Operator	Husky	Suncor Energy (Petro-Canada	Petrobras	PEMEX	PEMEX	PEMEX
Leased FPSO (Y/N)	N	N	Y	Y	Y	Y
Field or Location	White Rose	Terra Nova	Cascade, Chinoook	Various	Various	KuMaZu
Country	Canada	Canada	US GOM	Mexico GOM	Mexico GOM	Mexico GOM
Construction Type	New	New	Conversion	New	Conversion	Conversion
Mooring System Type	Internal Turret	External Turret	Disconnectable Turret Buoy	Turret	Dynamic Positioning	Internal Turret
Max Oil Production (MBOPD)	105	32	80	15	20	200
Oil Storage Capacity (MBBLS)	630	550	600	36	20	2200
Operating Water Depth (m)	120	94	2,600	–	–	100
Shipyard	South Korea, Canada	South Korea	Keppel (Singapore)	Norway	Norway	Singapore
Cost (in millions)	$2,350 (Canadian)	$1,600 (Canadian)	$740	–	–	–

Source: Wilhoit and Supan 2009

C.2.2.6 Yu'um K'akna'ab

The Lord of the Seas (Yu'um K'akna'ab in Mayan) was built in the Sembawand Shipyard in Singapore (PEMEX 2006).

C.2.3 FPSO Cost Estimate

As mentioned in Section C.2.2, there are only two estimates for new-build FPSOs in use in North American waters. The Terra Nova field FPSO has an estimated cost of $1.6 billion Canadian in 1996, which equates to about $1.176 billion 1996 U.S. dollars. Similarly, the White Rose FPSO's estimated cost was $2.35 billion Canadian in 2005 (about $1.95 in 2005 U.S. dollars) (BCan 2010). In 2008 U.S. dollars, the costs are about $1.613 billion and $2.149 billion, respectively (USDOL BLS 2010). The average cost, rounded to the nearest $100 million, is $1.9 billion.

This is only the cost for the vessel. A FPSO would be processing production from a subsea system. The data in Section C.1 provides an estimate of $200 million for a typical subsea system; thus ERG set the FPSO cost at $2.1 billion.

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APPENDIX D. PLATFORM FABRICATION SITES

ERG used the *OCS-Related Infrastructure in the Gulf of Mexico Fact Book* (Louis Berger Group 2004) as the starting list of platform fabrication facilities. ERG traced the history of each location since 2000 (the date of the data in Louis Berger Group [2004]) to determine 1) whether the yard still existed after Hurricanes Katrina, Rita, and Ivan roared through the region; 2) its current ownership; and 3) whether it still manufactured oil and gas production platforms. ERG searched the Dun & Bradstreet (D&B) *Million Dollar Directory* and other sources to obtain financial data for each location (D&B 2010).[33] Sections D.1 through D.4 contain the discussions for platform fabrication yards in Alabama, Mississippi, Louisiana, and Texas, respectively. Section D.5 includes the summary table.

D.1. ALABAMA

BAE Systems acquired Atlantic Marine Holding Company's operations in Mississippi (Moss Point),[34] Alabama (Mobile), and Florida (Mayport and Jacksonville [BAE Systems 2010]). Atlantic Marine is listed as BAE Systems Southeast Shipyards in the workboat.com directory as offering offshore vessel and rig repair and fabrication services. For this reason, ERG retains them in the set of fabrication facilities (Workboat 2010).

D.2. MISSISSIPPI

D.2.1. Friede Goldman Offshore Gulfport Yards

Friede Goldman Halter, Inc., went into bankruptcy in 2002. Singapore Technologies (VT Halter Marine) acquired the Halter Gulfport and Halter Gulfport Central yards but later resold them to Trinity Yachts and Gulf Coast Hatteras, respectively (Colton 2010). Both locations focus on yachts, not platform fabrication. Signal International was formed to acquire Friede Goldman assets, including the Pascagoula East and West yards (Friede Goldman Halter 2003).

D.2.2. Ingalls Shipbuilding Yard in Pascagoula

In March 2011, Huntington Ingalls was spun off from Northrup Grumman and is thus the owner of the Ingalls shipbuilding yard in Pascagoula at the time this report was written. Huntington Ingalls identifies itself as a shipbuilding business in its 2011 10k report. There is no mention of platform construction for the offshore oil and gas industry (Huntingon Ingalls 2011). As a result, ERG inferred that this location was unlikely to supply the offshore oil and gas industry with platforms and removed it from the list.

D.3. LOUISIANA

D.3.1. Not in Scope

ERG, in consultation with BOEM, eliminated three facilities from the subset of platform manufacturers (Mar-Con, Inc; Edison Chouest; and L-Con Marine Fabricators).

[33] Because the database was searched in 2010, the revenue and employment data reflect 2009 data. However, it is the proportion of revenues generated at each location that is used in the onshore distribution for MAG-PLAN; thus, the data are less affected by year-to-year variations in the absolute value of revenues.

[34] The Moss Point, Mississippi, facility operates under the name Millennium Industrial and Marine Solutions.

D.3.2. Ownership Changes and Name Changes

D.3.2.1. J. Ray McDermott, Inc. in Amelia

Bollinger bought J. Ray's Amelia Yard in 1997 (Business Wire 1997).

D.3.2.2. Sigma Industries, Inc. in Houma

The Houma, Louisiana, facility listed as Sigma Industries in Louis Berger Group (2004) is indicated as belonging to Chet Morrison Contractors in USEPA (2010b). The Chet Morrison Web site lists two locations within Houma, Louisiana, both of which have fabrication facilities (Chet Morrison 2010). ERG found D&B data for the Harvey, Louisiana, location (50 employees, $5.99 million in revenues). We could find employees for the Houma, Louisiana, location (500 employees) but not revenues. ERG extrapolated the $0.12 million per employee at the Harvey yard to the 500 employees at the Houma yard for an estimated $59.9 million in revenues. ERG infers that the D&B record contains the information for both locations.

D.3.2.3. Gulf Island Fabrication

Gulf Island Fabrication is a publicly owned company. At the end of 2009, the 10-K form reported a total of $311.529 million in revenues and 1,400 employees (Gulf Island Fabrication 2009). The fabrication yards are described as:

- Houma, Louisiana. East side of the Houma Navigation Canal (main fabrication yard and corporate headquarters).
- Houma, Louisiana. West side of the Houma Navigation Canal.
- Houma, Louisiana. East side of the Houma Navigation Canal, to the north of the main yard (formerly known as the Southport facility).
- Houma, Louisiana. Dolphin Services.
- Ingleside, Texas. Gulf Marine Fabrication.
- Aransas Pass, Texas. Gulf Marine Fabrication, north yard.

The D&B directory does not list the Gulf Marine Fabrication locations in the Gulf Island Fabrication corporate tree; only Louisiana properties are listed. ERG found one entry for Gulf Marine Fabrication with an address of Aransas Pass, but it appears to encompass both the Aransas Pass and Ingleside locations. The corporate brochure for Gulf Marine Fabrication shows them located near each other. ERG found separate entries in D&B for Dolphin Services and Southport Inc. ERG summed the entries for Dolphin, Southport, and Gulf Marine Fabrication. The difference between the total revenues for the company and the sum of the revenues at the known locations was assigned to the Houma East and West yards. This was also done for employment estimates for the Houma East and West yards. The Gulf Marine Fabrication facilities were purchased by Gulf Island Fabrication in 2006, and the yard is an addition to the Louis Berger Group (2004) list.

D.3.2.4. Allen Process Systems, Dynamic Industries, and Moreno Energy Group

Allen Process Systems, Dynamic Industries, and Moreno Energy Group have shared a complicated history. The Independent Review publishes lists of Acadiana's top 50 privately held companies. The 2010 list placed Moreno Group as number 1, with $619 million in 2009 revenues; however, it also describes the Moreno Group as several related businesses, of which Dynamic Industries is one. In 2009, Dynamic Industries was listed as number 5, with $313.9 million in revenues for 2008, having 2,000 employees, located in Iberia Parish, and with Mike Moreno as the top executive (The Independent 2009). That is, the $313.9 estimate for the 2008 revenues is the best estimate that ERG could identify for Dynamic Industries. The D&B database lists two locations in Harvey, Louisiana, and one location in each of Broussard, Louisiana; Alvin, Texas; and Dumas, Texas. However, the Dumas location is not listed on the Dynamic Industries' Web site as of March 2011; therefore, ERG removed this location (Dynamic Industries 2011). ERG lists one location in Harvey, Louisiana, and one in New Iberia, Louisiana, because the location with 950 employees has a street address in New Iberia and a mailing address with a P.O. Box in Harvey. Dynamic Industries acquired Allen Process Systems in 2006 (OGJ 2006), leading to an expansion of the New Iberia facility. ERG summed the reported revenues for the four locations reported in the D&B database. ERG assigned the difference between the $313.9 million reported for the company and the sum of the revenues for the other locations as the revenues for the New Iberia location.

D.3.2.5. Offshore Specialty Fabricators

Offshore Specialty Fabricators is another company with a hard-to-determine status.[35] The Offshore Specialty Fabricators Web site contains no information regarding further corporate ownership. The EPA database has two locations within Houma, Louisiana, for Offshore Specialty Fabricators and one for Aransas Pass, Texas. The EPA data lists "Offshore Express" as an alternative name for the company (USEPA 2010c). ERG verified Offshore Express as an alternative name for Offshore Specialty Fabricators through a search of Ward's Business Directory of U.S. Private and Public Companies (Ward 2008). A check of Offshore Seismics' Web site (listed in Ward 2008) mentions that it is part of the Offshore International Group of companies. Bloomberg Businessweek company information indicates that Offshore International Group is privately held, with subsidiaries in the oil and gas business in the United States and Peru (Bloomberg 2010). The Business Monitor International reports that Savia Perú—a joint venture formed by Ecopetrol and Korea National Oil Corporation—purchased Oil International Group in February 2009 for $900 million (Business Monitor International 2010). The report mentions the Peruvian operations as Oil International Group's main asset. However, it is not clear whether Savia Perú purchased all of Offshore International Group (implied by the language in Business Monitor International [2010]) or only the Peruvian operations, because Bloomberg (2010) reports total sales of $74.5 million for the six-month period ending June 30, 2010.

As a result of the above research, ERG identified four Offshore International Group locations:

- Offshore Specialty Fabricators Inc. in Houma, Louisiana.
- Offshore Specialty Fabricators Inc. in Houston, Texas.
- Fairway Offshore Exploration in Houston, Texas (also doing business as Offshore Specialty Fabricators Offshore Specialty Fabricators Inc.).
- Offshore Express Inc. in Aransas Pass/Ingleside, Texas (Offshore Specialty Fabricators Inc.).

[35] Dismukes et al. (2003) lists it as Offshore Specialty Fabricators, Inc., while the Web site lists it as a limited liability company (LLC).

The next step is to generate best estimates of the revenues and employees for each location. While the process will not result in precise estimates, the purpose of the estimates is to form a proportional basis for allocating platform fabrication expenditures to various locations in the GOM. Manta.com reports that 2009 revenues for Offshore Specialty Fabricators are between $50 million and $100 million and that the company has between 250 and 499 employees. These data are consistent with the $52.4 million and 300 employees reported for 2004 in Ward's Business Directory (Ward 2004). ERG used the midpoint estimate of $75 million in revenues. D&B (2010) lists revenues of $1.15 million and $17.5 million for the Offshore Specialty Fabricators and Fairway Offshore Exploration locations in Houston, Texas, respectively, while Manta.com lists revenues of $5 million to $10 million for Offshore Express in Aransas Pass/Ingleside, Texas. ERG estimated revenues of $49 million for the Houma, Louisiana, location by taking the difference between the sum of revenues for all reported locations and total revenues.[36] ERG assumes that the six-month earnings of $74.5 million reported in Bloomberg (2010) include additional operations such as Offshore Seismic Surveys.

D.3.2.6. UNIFAB International

In March 2005, Midland Fabricators acquired UNIFAB International and took the company private (UNIFAB 2005).

D.3.2.7. Bay Offshore/Berry Contracting

Berry Contracting, L.P., is the parent company for entities known under the names Bay Limited and Bay Offshore Limited (Bay Limited 2010; D&B 2010). The company Web site says it has shops and yards in Corpus Christi, Texas; Morgan City and Belle Chase, Louisiana; and the Port of Tampico, Mexico. The Morgan City yards are listed as being in Amelia, Louisiana (Bay Limited 2010).

Louis Berger Group (2004) also listed a Bay Offshore facility in New Iberia, Louisiana, but such a location is not mentioned on the company Web site (D&B [2010]) or the EPA database. Thus, ERG removed the New Iberia location from the updated list. While there are two locations in Amelia, Louisiana, the financial data in D&B (2010) appears to have been presented on a combined basis and listed under Morgan City. As a result, we list both yards under one entry in the updated list. D&B (2010) had separate listings for the Belle Chasse (Mosby Group), Louisiana, and Corpus Christi, Texas, locations.

D.4. TEXAS

D.4.1. First Wave Newpark Shipbuilding

ERG searched the EPA database and identified three locations for Newpark Shipbuilding in Galveston, Texas: Galveston Island, Pelican Island East, and Pelican Island West (USEPA 2010d). The Galveston Island location has an alternate name of First Wave Marine Inc. in the EPA record. ERG examined maps and found that Port Industrial Road merges with Harborside Drive and that Bludworth Marine Shipyard has the same street address. Bludworth Marine repairs commercial vessels but does not offer platform fabrication. Thus, this location is not in scope.

[36] ERG used the midpoint estimate of revenues for the Aransas Pass location.

The Pelican Island East location has an alternate name of Gulf Copper and Manufacturing (USEPA 2010d). Gulf Copper and Manufacturing offers rig repair and retrofitting for jackups and semisubmersibles (Gulf Copper and Manufacturing 2010). This location is in scope.

The Pelican Island West location appears with alternate names of SWSY Holdings, SWSY Holdings-Brady Island, and Southwest Shipyard (USEPA 2010d). Southwest Shipyard (Pelican Island West) builds and repairs barges (Colton 2010) and is out of scope.

D.4.2 Brown & Root Greens Bayou

Austin et al. (2008), Colton (2010), and U.S. Army Corps of Engineers (2006) indicate that the yard was sold off in pieces in 2004 and was still inactive in 2006. Based on the business address of its waterfront location, Spitzer Industries, Inc. appears to have taken over part of the property to manufacture subsea equipment (Spitzer 2010).

D.4.3 Kiewit Offshore Services

In 2001, Peter Kiewit Sons' built a state-of the art platform fabrication facility in Ingleside, Texas (Kiewit 2010). D&B lists 450 employees at this location but does not list revenues. The Hoovers.com company profile lists 500 employees and notes that the average annual revenue per industry worker is $350,000 (Hoovers 2010). If the facility earned average annual revenues per employee, the annual revenues would be calculated as $175 million. However, the D&B family tree for Kiewit Offshore Services includes an Omaha, Nebraska, location with revenues of $414.8 million. If this revenue number is associated with the 450 employees reported for the Ingleside location, then the average revenue per employee would be $922,000 or about 2.5 times higher than the average. Given that the Kiewit facility was new and state of the art in 2001, ERG considered it reasonable to accept the higher revenue per employee value. As a result, Table D-1 lists 450 employees and $414.8 million in revenues for the Ingleside, Texas facility.

D.4.4 Aker Gulf Marine

D&B lists 1,130 employees for the Aker Gulf Marine Ingleside, Texas yard but does not list revenues. In the absence of more definite information, ERG imputed the revenues based on the average annual revenue per employee of $350,000 reported in Hoovers (2010). The Aker Marine facility has imputed revenues of $396 million.

D.5 SUMMARY

The offshore platform fabrication industry supported more than 23,000 jobs in 2009 and represents approximately $3.7 billion in revenues (see Table D-1).

Table D-1

Summary of Platform Fabrication Facilities

Name	Current Owner	Former Owner	City	State	County	2009 Revenues (Millions)	Employment
Mobile Yard	BAE Systems	Atlantic Marine Holding Company	Mobile	AL	Mobile	$35.16	500
				Alabama Total		$35.16	500
New Iberia Yard	Cameron International Corp	Natco	New Iberia	LA	Iberia	$21.18	100
New Iberia Yard	Dynamic Industries, Inc.		New Iberia	LA	Iberia	$279.04	950
New Iberia Yard	Marine Industrial Fabrication	Unifab International, LLC	New Iberia	LA	Iberia	$32.00	120
New Iberia Yard	Omega Natchiq/ASRC	Omega Service Industries, Inc.	New Iberia	LA	Iberia	$67.00	475
Delcambre Yard	Shaw Group (Shaw Bagwell)		Delcambre	LA	Iberia	$34.53	300
Harvey Yard	Anders Construction		Harvey	LA	Jefferson	$0.25	3
Harvey Yard	Chet Morrison Contractors, Inc.		Harvey	LA	Jefferson	$5.99	50
Harvey Yard	Dynamic Industries, Inc.		Harvey	LA	Jefferson	$18.81	250
Harvey Yard	Houma Industries		Harvey	LA	Jefferson	$16.10	176
	Dynamic Industries, Inc.		Broussard	LA	Lafayette	$9.40	75
Harvey Yard	Production Mgmt Industries (PMI)		Golden Meadow	LA	Lafourche	$0.60	4
Mosby Unit	Berry Contracting, LP	Bay Offshore Ltd. Mosby Unit	Belle Chasse	LA	Plaquemines	$0.13	3
Belle Chasse Yard	Omega Service Industries, Inc.		Belle Chasse	LA	Plaquemines	$67.00	475
East/West/North Yards	Berry Contracting, LP	Bay Offshore Ltd.	Amelia	LA	Saint Mary	$54.57	200
Amelia Yard	Bollinger Shipyards	J. Ray McDermott, Inc.	Amelia	LA	Saint Mary	$42.99	396
	J. Ray McDermott		Morgan City	LA	Saint Mary	$15.07	100
Baldwin Yard	Superior Fabricators, Inc.		Baldwin	LA	Saint Mary	$4.60	40
South Louisa Yard	Twin Brothers Marine		Morgan City	LA	Saint Mary	$14.62	202
Houma Yard	Chet Morrison Contractors, Inc.		Houma	LA	Terrebonne	$59.90	500
Houma Yard	Dolphin Services, Inc.		Houma	LA	Terrebonne	$29.80	249
Houma Yard	Gulf Island Fabrication, Inc.	Southport, Inc.	Houma	LA	Terrebonne	$33.00	200
Houma Yard	Gulf Island Fabrication, Inc.		Houma	LA	Terrebonne	$206.83	351

Table D-1. Summary of Platform Fabrication Facilities (continued)

Name	Current Owner	Former Owner	City	State	County	2009 Revenues (Millions)	Employment
Gibson Yard	Max Welders, Inc.		Gibson	LA	Terrebonne	$8.90	90
Houma Yard	Offshore Specialty Fabricators, Inc.		Houma	LA	Terrebonne	$49.00	150
Abbeville Yard	Acadian Contractors		Abbeville	LA	Vermilion	$16.30	300
Abbeville (Port of Vermillion) Yard	Gulf Coast Marine Fabricators		Abbeville	LA	Vermilion	$15.75	45
					Louisiana Total	$1,103.36	5,804
Pascagoula East Yard	Signal International	Friede Goldman Offshore	Pascagoula	MS	Jackson	$398.00	1,400
Pascagoula West Yard	Signal International	Friede Goldman Offshore	Pascagoula	MS	Jackson		
	LeTourneau Technologies		Vicksburg	MS	Warren	$249.06	850
					Mississippi Total	$647.06	2,250
	Dynamic Industries, Inc.		Alvin	TX	Brazoria	$5.24	30
Brownsville Yard	Keppel Amfels, Inc		Brownsville	TX	Cameron	$270.50	1,528
Pelican Island East	Gulf Copper & Manufacturing	Newpark Shipbuilding Pelican Island East	Galveston	TX	Galveston	$4.50	5
Channelview Yard	Delcor	Delta Engineering Corporation	Channelview	TX	Harris	$37.80	250
	Fairways Offshore Exploration	aka Offshore Specialty Fabricators, Inc.	Houston	TX	Harris	$17.47	22
	Offshore Specialty Fabricators, Inc.		Houston	TX	Harris	$1.15	10
	Seahorse Platform		Houston	TX	Harris	$0.10	2
Turbofab Facility	Solar Turbine Inc.		Channelview	TX	Harris	$35.03	200
Greens Bayou Yard	Spitzer Industries	Brown & Root Greens Bayou	Houston	TX	Harris	$206.87	505
	Signal International		Port Arthur	TX	Jefferson	$8.68	80
	United Marine Shipyard		Port Arthur	TX	Jefferson	$11.20	252
	Berry Contracting, LP		Corpus Christi	TX	Nueces	$420.62	850
	Signal International		Orange	TX	Orange	$29.30	305

Table D-1.

Summary of Platform Fabrication Facilities (continued)

Name	Owner	Former Owner	City	State	County	2009 Revenues (Millions)	Employment
Ingleside Yard	Aker Gulf Marine		Ingleside	TX	San Patricio	$395.50	1,130
Ingleside Yard	Gulf Marine Fabricators		Ingleside	TX	San Patricio	$41.90	600
	Kiewit Offshore		Ingleside	TX	San Patricio	$414.80	450
Ingleside Yard	Offshore Specialty Fabricators, Inc.		Aransas Pass	TX	San Patricio	$1.15	10
Ingleside Yard	State Service Co., Inc.		Ingleside	TX	San Patricio	$42.19	93
					Texas Total	**$1,944.00**	**6,322**
Grand Total						**$3,729.59**	**23,430**

Source: D&B (2011) for revenues and employment data; see text for details for specific locations.

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APPENDIX E. SEMISUBMERSIBLE STRUCTURE COSTS

ERG examined the total and component costs for semisubmersible structures in the GOM, as well as where the components were manufactured. This was done to estimate the proportion of the expenditures that flow outside the United States.

E.1 DESCRIPTION

A semisubmersible is a type of floating production system. Semisubmersibles' working decks are supported by columns on hulls or pontoons. Depending on the design, it might be towed or moved to the drill site under its own power. When on location, the hulls or pontoons are flooded such that most of the mass of the structure lies below the water surface. Because of this, the structure shows little front-to-back or side-to-side rolling or pitching. The up-and-down motion still continues, but this is addressed by the riser system. The production structures typically are anchored or use dynamic positioning to stay in place.

E.2 TYPICAL COSTS

ERG identified a set of seven semisubmersible production structures in the GOM from the 2008 worldwide survey of semisubmersible floating production systems and units (Wilhoit and Supan 2008).[37,38] Table E-1 lists the water depth, first production date, and date of the reported cost information.

Where possible, we identified total cost as well as separate costs for the hull, topsides, integration, conversion, and installation. This means that the sum of the individual entries might not equal the total cost. In one case, we had total cost and individual costs for all but one category and used the difference between total cost and the sum of the individual costs to impute the value for the missing component. These are shown in bold italic font in Table E-1.

Collecting cost information is not straightforward. Even when ERG found a cost, some of the remaining questions were:

- Is this the total project cost or only the company's share?
- Does the cost cover one or more than one project?
- What is included in the costs (e.g., hull, topsides, integration, installation)?
- Does it include the cost for drilling the wells associated with the production structure?

We discuss each structure separately along with the assumptions ERG made in interpreting the data. None of the references provide a cost estimate with a base year for the dollars. ERG thus assumes the value is in current dollars and the date of the publication is used as the date for the dollars.

E.2.1 Atlantis

For the Atlantis semisubmersible located on Green Canyon 787, ERG found two estimates for total project cost—$3.7 billion and $2 billion. Although the estimates differ by a factor of

[37] The Helix Producer 1 is listed on the poster; however, it was converted from a train ferry to a ship-shape floating production unit (CSC n.d.). ERG determined it was different enough from the semisubmersible vessels to exclude from the analysis.

[38] ERG found the semisubmersible that produces from the Gomez field listed as "Gomez" in Nixon et al. (2009) and as "Innovator" in ATP reports.

two, the magnitude of the difference between the two would result in substantial differences in the socioeconomic impacts estimated in MAG-PLAN. *JPT Online* (2007) and Macdonald-Smith and Gismatulin (2007) provide the total cost of $3.7 billion, with BP being the majority owner at 56 percent (JPT 2007). BP's share would come to an estimated $2.07 billion. J. Ray McDermott (2008) and SubseaIQ (2010) list the project cost at $2 billion. However, ERG found references for parts of the work where the total exceeded $2 billion, so Table E-1 lists $3.7 billion as the total cost.

ERG could not locate the estimated cost for the hull constructed at the Daewoo Shipbuilding and Marine Engineering (DSME) shipyard in Korea. Offshore (2003) and SubseaIQ (2010) report that J. Ray McDermott got a $600 million contract to construct the topsides. SubseaIQ (2010) notes that Heerema Marine was awarded a $400 million contract for the installation and associated pipelines and gathering lines, and Subsea 7 was awarded a $30 million contract for the installation of 26 miles of umbilicals. This is the $430 million entry for installation in Table E-1. Bardex Corporation and FMC Technologies were awarded contracts for unspecified amounts for the mooring systems and subsea trees, manifolds and connection systems (SubseaIQ 2010).

Beshur (2005) discusses the work assembling the hull and topsides at the Kiewit shipyard. It mentions that the project will involve more than 1,000 workers and cost more than $1 billion. Beshur (2005) reports on local business for the Corpus Christi Caller Times. J. Ray McDermott (2008) mentions that the integration of the topsides and hull would take place in Corpus Christi facilities but does not specify the contractor or contract value. As a result, ERG estimates the integration work to be $1 billion in Table E-1. Thus, ERG could find estimates totaling $2.4 billion before hull, mooring system, subsea trees, manifolds, and connection system costs are included.

Table E-1

Semisubmersible Costs

Facility Name	Atlantis	Independence Hub	Innovator/ Gomez	Na Kika	Blind Faith	Thunder Hawk	Thunder Horse	Average
Water Depth (ft)	7,072	7,918	2,998	3,070	6,494	5,707	6,065	
First Production Date	2007	2007	2006	2004	2008	2009	2008	
Cost Date	2005	2006	2005	2001	2008	2009	2008	
CURRENT DOLLARS (millions)								
Hull Cost		$50	$50		$120		$380	
Topsides Cost	$600	$396		$625	***$720***		$600	
Integration Cost	$1,000				$25	$303		
Conversion Cost			$30					
Installation Cost	$430			$635	$35	$23	$30	
Total, as reported	$3,700	$2,000	$80	$1,260	$900	$326	$5,000	
2008$ (millions)								
Hull Cost		$53	$55		$120		$380	$152
Topsides Cost	$661	$423		$760	***$720***		$600	$633
Integration Cost	$1,102				$28	$302		$477
Conversion Cost			$33					
Installation Cost	$474			$772	$35	$23	$30	$267
Total, as reported	$4,077	$2,136	$88	$1,532	$900	$325	$5,000	$2,008

Note: Total costs and component costs identified separately; thus, the sum of component costs may not equal the total reported cost.

Source: JPT (2007); Macdonald-Smith and Gismatulin (2007); SubseaIQ (2010); Enterprise (2006); Alexander's Gas & Oil Connections (2006); ATP 2005; USDOI MMS (2004); McCaul 2001; energyme.com (2005); Solholm (2005); Rigzone (2005); Kiewit (2008); SBM 2009a; Upstream (2007); Magers (2005) and Lang (2008).

E.2.2 Independence Hub

Teasing apart the semisubmersible costs for Independence Hub introduces a different set of complications. First, the Independence Project consists of a semisubmersible production structure (Independence Hub), a pipeline tying the structure to onshore facilities (Independence Trail), and the subsea connections from the gas fields to the structure (Independence Subsea). Second, an energy company—Enterprise Products Partners, L.P.—is the majority owner (80 percent) of Independence Hub and owner of the Independence Trail (100 percent), while five independent exploration and production companies[39] own their respective portions of the subsea completions and flow lines tying six gas fields to Independence Hub (Enterprise n.d.; Alexander's Gas & Oil Connections 2006; Anadarko 2008).[40] As a result, ERG sometimes needs to ascertain whether cost information presented by Enterprise Products Partners, L.P represents the semisubmersible structure, pipeline, or both, or whether costs reported for the Independence Project include the subseabed completions.

Enterprise (n.d.), Alexander's Gas & Oil Connections (2006), and SubseaIQ (2010) report total costs for the project as $2 billion. The $50 million cost estimate for Independence Hub's hull is from the Jurong shipyard's announcement of the contract award (SembCorp 2005).

Anadarko (2004), Offshore (2005), and USDOI MMS (n.d.) say the Independence Hub structure is estimated to cost $385 million. Anadarko (2008) mentions that Enterprise GP Holdings invested more than $650 million to design, construct, and install the structure and associated pipeline, which could be consistent with a $385 million structure and $281 million pipeline. Enterprise (2006), however, states that the platform and pipeline costs are estimated at $445.9 million and $281.3 million, respectively. ERG considers that the semisubmersible structure cost total of $446 million is more accurate and that it includes the hull cost.[41] As a result, Table E-1 shows the $50 million for the hull and the remaining $396 million for the topsides and installation

At this point, ERG has identified only $446 million in costs for a $2 billion project. A clue for the other expenditures might be found in Anadarko (2006), where the company announced a capital budget of $4 billion. Twenty-three percent of the budget (or approximately $920 million) is allocated to the deepwater GOM. Furthermore, Anadarko mentions that about 10 percent (about $400 million) of the total budget will go toward installing facilities that link the Anadarko gas fields to Independence Hub.[42] Given that there are four other companies linking up to Independence Hub, one possible interpretation is that the $1.5 billion "gap" represents the expenditures by the oil and gas companies to develop and link their remote gas fields to Independence Hub.

[39] Anadarko Petroleum Corp., Dominion Exploration & Production Inc., Kerr-McGee Oil & Gas Corp., Spinnaker Exploration Co., and Devon Energy Corp., also referred to as the Atwater Valley Producers Group.

[40] The companies get access to gas processing capacity, pay a monthly fee (regardless of capacity used), and pay a processing fee dependent on the capacity used.

[41] ERG considers the value published in a 10-K form filed with the Securities and Exchange Commission in 2006 to be of higher data quality than a value published in a 2005 industry magazine.

[42] Another 10 percent is spent to bring six wells online at the Marco Polo hub facility. That is, Anadarko is spending its 2006 capital budget for the GOM on Independence Hub and Marco Polo.

E.2.3 Innovator/Gomez

ATP Oil and Gas decided to develop a marginal gas field in Mississippi Canyon block 711 using a converted semisubmersible drilling unit rather than building a new facility (Paganie 2006). ATP purchased the Rowan Midland from Rowan for a price of $50 million (ATP 2005) and renamed it the ATP Innovator (ATP 2006). The semisubmersible was converted at Signal International's Port Arthur, Texas, yard. Omega Services of New Iberia, Louisiana, supplied the process modules, and Intermoor supplied the mooring system of polyester rope attached to the seabed via suction-embedded plate anchors (SEPLAs). Innovator marked the first floating production system to use SEPLA anchors in the GOM (Paganie 2006 and Signal 2010).[43] SubseaIQ (2010) lists the development cost for the production facility as $80 million.[44] ERG assumes that this represents the $50 million purchase price for the Rowan Midland plus the cost to convert and install the structure (i.e., contracts to Omega Services and Intermoor).

E.2.4 Na Kika

The total cost for Na Kika is $1.26 billion (USDOI MMS 2004, McCaul 2001). McCaul (2001, 2003) provides a further breakdown:

- $625 million for fabrication and installation of the production structure and pipeline
- $317.5 million for fabrication and installation of the subsea components
- $317.5 million for drilling and completion of wells

That is, roughly half for the structure and pipeline and one-quarter each for the subsea components and wells.

E.2.5 Blind Faith

The total capital cost for the development of Blind Faith is estimated at $900 million by SubseaIQ (2010). ERG found cost estimates for the hull, installation, and integration; Aver Kvaener was awarded a contract for the hull and installation at $120 million and $35 million (SubseaIQ 2010, energyme.com 2005, Solholm 2005, Rigzone 2005), respectively, and $25 million was contracted to Kiewit for the integration (Kiewit 2008). The topsides were fabricated by Gulf Island LLC, a wholly owned subsidiary of Gulf Island Fabrication, but ERG was unable to find the cost of the contract (Gulf Island 2005). ERG estimated the cost to be $720 million because it is the only missing component of the total $900 million capital cost. Blind Faith is primarily held by Chevron, with a 62.5 percent interest, and Kerr-McGee holds the remaining interest.

[43] The poster compiled by Wilhoit and Supan (2008) lists the fabrication yard as Levingston Shipyard and Rowan Companies as the Conversion/Integration Yard. Signal (2010) lists the conversion work as occurring in their Texas shipyard.

[44] Paganie (2006) says the total capital expenditures associated with acquisition, conversion, and other expenses totaled about $100 million. However, Paganie (2006) also states the acquisition price for Rowan Midland as $60 million, when ATP reports the cost as $50 million (ATP 2005). Because the structure cost in Paganie 2006 is high compared to what is reported by ATP, ERG chose to use the SubseaIQ estimate of $80 million for the total cost.

E.2.6 Thunder Hawk

Thunder Hawk commenced first production in July 2009. The semisubmersible was built and is owned by SBM Offshore, a Dutch holding company. Murphy Oil operates the unit, and all users pay a day rate and some value of production to SBM Offshore. (See Independence Hub, Section E.2.2 for a description of a similar financial arrangement.) ERG had difficulty finding cost information for this unit. SBM Offshore announced the lease order for the Thunder Hawk semisubmersible in a news release that also included a mobile production unit with storage for Yme, North Sea; turnkey orders for three semisubmersible drilling units; and orders for drilling units and process modules. The total value of the orders was $1.2 billion (SBM 2006), but only a fraction of that is attributable to Thunder Hawk. ERG found an entry in the 2009 SBM Offshore annual report listing an outstanding loan balance of $303 million for Thunder Hawk (SBM 2009a). This is likely to be a low estimate because it includes only what SBM offshore financed through long-term debt. It does not include any part of SBM Offshore's revolving debt or capitalized/expenses interest payments. However, the $303 million estimate, while low, appears credible. SBM Offshore's brochure on semisubmersible production units mentions that Thunder Hawk is a near-clone of Independence Hub but is meeting updated design requirements (SBM 2009b). The $303 million estimate for Thunder Hawk is similar to the $396 million estimate for Independence Hub.

The only other cost component for which ERG could find an estimate was for installing the mooring system, transport, and hook-up of the facility. Aker Kvaerner won the $23 million contract (Upstream 2007).

E.2.7 Thunder Horse

The Thunder Horse field was discovered in 1999, but it took 10 years to become the extremely productive field it currently is (Knott 2009). Given the water depth (6,050 feet), reservoir depth (between 14,000 to 19,000 feet below the seabed), and reservoir temperature and pressure (between 13,000 to 18,000 psi and between 190 to 270°F), developing the Thunder Horse field would take a number of new technologies (Knott 2004).

Figure E-1. Thunder Horse
Source: ©BP

BP decided to develop the field with a semisubmersible production unit, also called Thunder Horse. When it was built in 2004–2005, it was the largest semisubmersible unit in the world, with a height of about 450 feet from the base of the hull to the top of the drill rig and a deck area of about 3 acres (USDOI MMS 2005 and Figure E-1). It was originally scheduled for installation in 2005; however, as sometimes happens with cutting-edge projects, some difficulties cropped up along the way to first production. Thunder Horse was towed to its production site in April 2005. Hurricane Dennis blew through in early July 2005 and afterward, the unit was tilted to about 20 to 30 degrees. The cause of the tilting was not the hurricane but rather faults in the ballast/bilge water hydraulic control systems. The remedial work was extensive and took about a year to complete. In mid-2006, when the unit was scheduled to go into production, BP found faulty welds in the subseabed manifolds due to unforeseen chemical interactions and metal embrittlement. To fix the damage, BP had to retrieve the subseabed equipment, refurbish it, and return it to the seabed. Two more steps were necessary for successful completions: 1) the development of a nitrogen gas cap in the annulus to absorb the effects of packer fluid expansion and 2) contracting and reducing the variability in the copper plating on the connection threads.[45] Thunder Horse came onstream in June 2008 (Knott 2009). BP notes that nearly 14 million man-hours have been expended on the project since Thunder Horse went offshore in 2005 (Knott 2009).

ERG considers the story of bringing Thunder Horse into production to explain the two total cost estimates it found in the literature. Knott (2001) and Tyson (2008) mention that the production facility cost more than $1 billion. SubseaIQ (2010) reports that Subsea 7 got a $30 million contract to install 37 miles of umbilicals and subsea structures. Bradbury (2002) says that Daewoo Shipbuilding and Marine Engineering got a $380 million contract to build the semisubmersible hull, and that J. Ray McDermott "has dedicated its whole site to build process topsides modules for the Thunder Horse PDQ [production, drilling, and quarters] and for the three spars for Atlantis, Holstein, and Mad Dog in a $600 million deal." Thus, an upper bound estimate for the Thunder Horse topsides is $600 million. These three cost pieces (hull, topsides, and subsea) sum to $1.01 billion, which is consistent with Knott (2001) and Tyson (2008).

Two references (Magers 2005 and Lang 2008), however, describe Thunder Horse as about a $5 billion investment. Given the 14 million man-hours and the analyses, rebuilding, and re-equipping needed to get Thunder Horse into production, ERG considers $5 billion to be a more likely estimate of the total cost by 2008.

E.2.8 Cost Summary

The estimated semisubmersible costs in 2008$ range from a low of $88 million for Innovator, which was converted from an existing vessel, to $5 billion for Thunder Horse (see Table E-1). Average component costs are calculated on a row basis (where the divisor is the number of entries with data), so the sum of the average costs for the hull, topsides, integration, conversion, and installation does not equal the average total cost.

E.3 MANUFACTURING LOCATIONS

Table E-2 provides more detail on each of the semisubmersible structures in Table E-1, including where the different major components were manufactured. The following companies built the hulls:

- DSME (Daewoo Shipbuilding and Marine Engineering, Korea)
- Jurong Shipyard, Singapore
- Signal International, Texas
- HHI (Hyundai Heavy Industries-Korea)
- Aker Verdal (Norway)
- Dyna-Mac Engineering Services (Singapore)

[45] Variability in the deposition of copper plating can induce hydrogen atoms in the connection threads. This leads to metal embrittlement and potential failure (Knott 2009).

For the new-build vessels, the hull is consistently manufactured at foreign locations. Topside manufacturing and the integration of the pieces, for the most part, happen at GOM locations. The exception is Na Kika, where everything was done in Korea. The work for the sole example of a conversion took place in the GOM region. Given the average cost data in Table E-1, approximately 7.5 percent of a semisubmersible's cost is spent overseas on hull manufacture.

Table E-2
Semisubmersible Manufacturing Locations

Facility Name	Atlantis	Independence Hub	Innovator/ Gomez	Na Kika	Blind Faith	Thunder Hawk	Thunder Horse
Vessel Owner	BP & BHP	Enterprise & Helix Energy Solutions	ATP	Shell	Chevron	SBM Offshore	BP & Exxon Mobile
Vessel Operator	BP	Anadarko	ATP	BP	Chevron	Murphy	BP
Field Operator	BP	Anadarko	ATP	Shell	Chevron	Murphy	BP
Field(s)	Green Canyon 787	Atlas, Atlas NW, Cheyenne, Jubilee, Merganser, Mondo NW, Q, San Jacinto, Spiderman and Vortex	Mississippi Canyon 711	Kepler, Ariel, E Anstey, Hershel, Fourier and Coloumb	Mississippi Canyon 650, 695 & 696	Mississippi Canyon 736	Mississippi Canyon 778
Water Depth (ft)	7072	7918	2998	3070	6494	5707	6065
Year, First Production	2007	2007	2006	2003	2008	2009	2008
Wells, Total	22	16	6	12	5	4	25
Wells, Producing	16	16	6				12
Subsea (Y/N)	Y	Y	Y	Y	Y	Y	Y
Fabrication Yard, Hull	DSME	Jurong		HHI	Aker Verdal	Dyna-Mac	DSME
Fabrication Yard, Topside	J Ray McDermott	Kiewit		HHI	Gulf Island	Kiewit Offshore	J Ray McDermott
Conversion/Integration Yard	Kiewit	Kiewit	Signal International	HHI	Kiewit	Kiewit Offshore	Kiewit
General Contractor	BP	Enterprise	Rowan	Shell E & P	Aker Solutions	SBM Atlantia	
Capacity, oil MBOPD	200	0	20	110	45	60	250
Capacity, gas MMscfd	180	1000	100	425	45	70	200
Quarters Capacity	100	16	98	60	na	38	188

Source: Wilhoit and Supan 2008; Signal 2010

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