Economic Analysis Methodology for the 2017–2022 Outer Continental Shelf Oil and Gas Leasing Program

BOEM

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Abbreviations and Acronyms

2016 National Assessment	*Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2016*
AEO	*Annual Energy Outlook*
APEEP	Air Pollution Emission Experiments and Policy
API	American Petroleum Institute
bbl	barrels of oil
BBOE	billion barrels of oil equivalent
bcf	billion cubic feet
BLM	Bureau of Land Management
BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
BOP	blowout preventer
BSEE	Bureau of Safety and Environmental Enforcement
Btu	British thermal units
CCDF	Complementary cumulative density function
CO_2	carbon dioxide
CO	Carbon monoxide
COS	Center for Offshore Safety
DOE	Department of Energy
DPP	2017–2022 OCS Oil and Gas Leasing Draft Proposed Program
DMME	Virginia Department of Mines, Minerals and Energy
E&D	exploration and development (scenario)
EIA	Energy Information Administration
EIS	environmental impact statement
Final Programmatic EIS	*2017–2022 OCS Oil and Gas Leasing Program Final Programmatic Environmental Impact Statement*
GHG	greenhouse gas
GOADS	Gulfwide Offshore Activities Data System
GOM	Gulf of Mexico
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
HEA	habitat equivalency analysis
ICCOPR	Interagency Coordinating Committee on Oil Pollution Research
ITOPF	International Tanker Owners Pollution Federation
JITF	Joint Industry Task Force
LWC	loss of well control
MarketSim	Market Simulation Model
mcf	thousand cubic feet
MMBOE	million barrels of oil equivalent
MMS	Minerals Management Service
MWCC	Marine Well Containment Company
NAA	No Action Alternative

NEMS	National Energy Modeling System
NEV	net economic value
NO_x	oxides of nitrogen
NSV	net social value
OCS	Outer Continental Shelf
OESC	Ocean Energy Safety Advisory Committee
OMB	Office of Management and Budget
OECM	Offshore Environmental Cost Model
OESI	Ocean Energy Safety Institute
OSPRS	Oil Spill Preparedness and Response Subcommittee
PFP	2017–2022 OCS Oil and Gas Leasing Proposed Final Program
$PM_{2.5}$	Particulate matter with a diameter equal to or less than 2.5 microns
PM_{10}	Particulate matter with a diameter equal to or less than 10 microns
R&D	research and development
SEMS	Safety and Environmental Management System
SIMAP	Spill Impact Model Application Package
SO_2	sulfur dioxide
TAPS	Trans-Alaska Pipeline System
TVA	Tennessee Valley Authority
ULCC	ultra large crude carrier
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
VOC	volatile organic compound
WCI	Well Control Institute
WEB2	When Exploration Begins, version 2
WRAP	Western Regional Air Partnership

Overview

The Bureau of Ocean Energy Management (BOEM) is an agency in the U.S. Department of the Interior responsible for managing development of the nation's offshore resources in an environmentally and economically responsible way.

BOEM has oversight responsibility on oil and gas leasing activities within the Outer Continental Shelf (OCS). Section 18 of the OCS Lands Act requires the Secretary of the Interior to prepare and maintain a schedule of proposed OCS oil and gas lease sales determined to "best meet national energy needs for the five-year period following its approval or reapproval." The proposed oil and gas leasing program must be prepared and maintained in a manner consistent with the principles specified in Section 18 of the OCS Lands Act.

This Economic Analysis Methodology document is referenced in the *2017–2022 Outer Continental Shelf Oil and Gas Leasing Proposed Final Program* (2017–2022 PFP) and provides supplemental explanations of the analytic approaches used for the analyses in the decision document, including comprehensive tables and references to original studies. This document is divided into four Chapters:

1. Chapter 1, Net Benefits Analysis
2. Chapter 2, Catastrophic Oil Spills
3. Chapter 3, Non-monetized Impacts
4. Chapter 4, Fair Market Value Analysis: WEB2 Methodology

Chapter 1 Net Benefits Analysis

1.1 INTRODUCTION

This chapter describes the factors considered and the calculations behind the net benefits analysis found in Section 5.3 of the 2017–2022 PFP.

Since the theoretical foundation and background for the net benefits analysis are covered extensively in prior program documents (BOEM 2012a), they are not repeated in this paper. However, BOEM has improved the simulation models and updated data sources used for estimating the program's net benefits. The ensuing results reflect the outputs generated by these models and timely geological, environmental, and economic data and evaluations needed to make credible and timely estimates of the PFP's incremental net benefits. Only currently implemented laws and regulations are considered in this analysis.

The net benefits analysis does not incorporate the costs of low-probability/high-consequence events such as catastrophic oil spills. To capture the possible impacts of the highly unlikely catastrophic oil spills, they are considered separately in Chapter 2, Catastrophic Oil Spills of this methodology document. The rarity and unpredictable nature of the many factors influencing the severity of a large oil spill's impact make efforts to quantify expected costs far less meaningful than the other measures developed by the Offshore Environmental Cost Model (OECM) and Market Simulation Model (*MarketSim*).[1]

The net benefits analysis does not incorporate the social cost of carbon relating to greenhouse gas emissions (GHGs) for oil and gas produced on the OCS. To analyze and quantify those downstream costs due to GHG emissions, they are considered separately in the technical report, *OCS Oil and Natural Gas: Potential Lifecycle Greenhouse Gas Emissions and Social Cost of Carbon* (BOEM 2016a).

The following sections provide more complete tables and explanations for sections previously summarized in Section 5.3 of the 2017–2022 PFP. Analysis in this chapter references other BOEM reports on the OECM documentation, covered in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a) and *Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015b), and the *MarketSim* documentation, *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2015 Revised Market Simulation Model* (BOEM 2015c).

[1] The OECM calculates the environmental and social costs of the Program options for each program area. The *MarketSim* estimates the energy market's response to the program's Exploration and Development (E&D) scenarios, calculates conservation and energy substitutions for OCS oil and gas under the No Sale Option in each program area, and determines the net change in consumer surplus anticipated from the program.

1.2 BACKGROUND

The net benefits analysis is a benefit-cost assessment by program area of the national gain from anticipated production of economically recoverable oil and natural gas resources expected to be leased and discovered as a result of the Five-Year Program. Resources leased as a result of previous programs are not part of the program decision and, therefore, not considered in this analysis. The results summarized in the decision document provide the Secretary of the Interior benefit and cost estimates for holding a lease sale (or sales) or selecting the No Sale Option in any or all of the four program areas.[2] The measure of incremental net benefits reflects the net producer, consumer, and fiscal gains to the nation above the finding and extraction costs, as well as the environmental and social costs, from the anticipated exploration, development, and production in each program area. The analysis also adds to the program area estimates of the environmental and social costs avoided, and deducts the domestic profit forgone, which are associated with obtaining replacement energy from other sources should any of the No Sale Options be selected.

Selection of the No Sale Option in any of the program areas means that no new leasing would take place in that area for at least five years.[3] Without new leasing, production on new leases could not occur in the program area. This would reduce future domestic oil and natural gas supply but cause little change in domestic demand for energy. The resulting gap between domestic demand and supply would be met by additional imports (primarily foreign-sourced oil delivered by supertankers), more domestic onshore oil and gas production, and other energy market substitutes. Energy usage would be slightly lower than it would be with the sale(s) due to a slight increase in domestic prices. Section 1.3.2, Market Simulation Model, details how *MarketSim* estimates the energy sources that would replace OCS production anticipated from this program should the No Sale Option be chosen in one or more program areas.

The net benefits analysis provides the Secretary of the Interior with a logically consistent basis for considering the values and alternative sale options for each program area. It only includes the effects of the upstream oil and gas activities, not those associated with the downstream production (e.g., refining) or consumption of petroleum products. Since the Secretary's Five-Year Program decision is a decision on the leasing program options, the net benefits analysis focuses on those options and not on other policy levers that might alter the baseline energy forecast. The baseline is a energy forecast, based on current actual (not proposed) laws and policies, provided by the U.S. Energy Information Administration (EIA) in the *Annual Energy Outlook* (EIA 2015).[4] Although other changes such as new energy efficiency standards and renewable energy technologies or policies are not considered within the net benefits analysis, they are discussed in a related program document titled *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2:*

[2] If the No Sale Option is selected for each program area, it is identical to the no action alternative (NAA) referred to in the Final Programmatic EIS. The effects of the NAA are the market response and corresponding environmental and social costs absent a Five-Year Program.

[3] Conceivably, the oil and gas supply may only be delayed until a future program could offer the No Sale Option area, but this analysis does not incorporate that possibility. The substantial present value discount that would be applied to any such production makes its omission from future supplies largely insignificant for this analysis.

[4] The 2016 *Annual Energy Outlook* bases its forecast on the Federal, state, and local laws and regulations that are effective as of late 2015. These projections do not include the effects of any pending or proposed legislation, regulations, and standards. As mentioned elsewhere, the 2016 AEO assumes the President's Clean Power Plan is implemented.

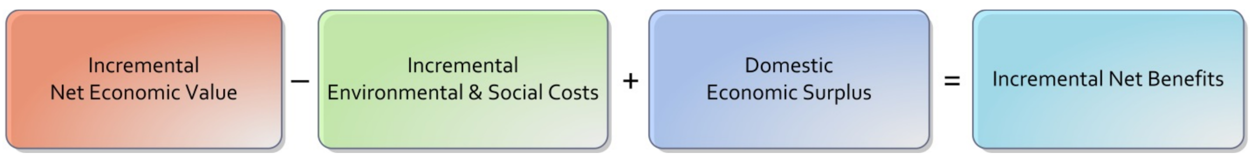
Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM) (BOEM 2015b).

1.3 METHODOLOGY

1.3.1 Overview of the Net Benefits Analysis

The net benefits analysis enumerates three levels of domestic benefits and costs associated with the program: incremental net economic value (NEV), incremental environmental and social costs, and domestic economic surplus. All three are combined in the calculation of the incremental net benefits. Figure 1-1: Components of the Net Benefits Analysissummarizes the calculations completed for each program area to quantify the private and social gains and losses associated with adopting the proposed decision option for that area, as opposed to choosing the No Sale Option.

Figure 1-1: Components of the Net Benefits Analysis



The first box in Figure 1-1 measures the incremental NEV, sometimes called economic rent, generated by the new OCS production.[5] The incremental NEV can be viewed as the profit available to be shared by the oil industry and the Government from producing the OCS resources offered. Because this is a surplus remaining after the costs of exploration and production have been subtracted from gross revenue, it can be shared between producers and Government without distorting the allocation of capital and labor to this activity. To the extent that factors of production employed as a result of sales in the program area have less lucrative opportunities elsewhere, the selection of the No Sale Option would impose additional private costs in the form of lost wages, etc. This analysis ignores these potential private losses because no reliable measures exist to calculate them. However, the NEV generated from OCS activity is reduced by an estimate of what would have been generated from the production of domestic energy substitutes with selection of the No Sale Option.

The second box measures the incremental environmental and social costs of each program area by incorporating the external costs of the OCS activity relative to those from the energy substitutes that would exist with selection of the No Sale Option.[6] Such external costs occur because producers and consumers of offshore oil and gas resources do not bear all the costs generated by the program. The process used here estimates both the external costs associated with the anticipated OCS production in a program area and those that would arise from replacements for that production should the No Sale Option be selected. Because the Net Benefits Analysis is an incremental analysis and includes the replacement energy sources in the absence of a new OCS program, the net change in U.S. demand is relatively unchanged regardless of whether the program is approved.

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[5] Economic rent is typically defined as payment for goods and services beyond the amount needed to bring the required inputs into a production process and sustain supply.

[6] External costs occur when oil and gas production results in effects like air pollution that cause uncompensated environmental costs or loss of property value that cause uncompensated social costs.

The third box adds the domestic economic surplus gain from each program area. Economic surplus is composed of both consumer and producer surplus. Consumer surplus refers to the benefit buyers enjoy because they do not have to pay as much as they would have been willing to for the good consumed. Producer surplus occurs when producers receive more than the minimum price they would have been willing to accept to produce and sell the good. Oil and gas supplied from each program area increases domestic consumer surplus by reducing oil and natural gas prices and increasing overall consumption slightly. However, it also decreases both domestic and foreign producer surplus by reducing the price producers receive and by displacing some sales they would make under the No Sale Option. As the net benefits analysis considers impacts that occur to the United States, the analysis nets out the loss of producer surplus that accrues to domestic producers. Therefore, the domestic economic surplus reflects the difference between the gain to consumers from lower-priced domestic consumption and the loss to domestic producers from the lower prices received.

1.3.2 Market Simulation Model

MarketSim estimates the substitutions for offshore oil and gas production that would occur in the absence of sales in each of the program areas. *MarketSim* calculates the additional imports, onshore production, fuel switching, and reduced consumption of energy that would replace the production in each program area should any of the No Sale Options be selected, as well as the associated change in net domestic consumer surplus.

MarketSim is a Microsoft Excel-based model for the oil, gas, coal, and electricity markets calibrated to a special run of the EIA's National Energy Modeling System (NEMS). The baseline used in the *MarketSim* is a modified version of the EIA's 2016 *Annual Energy Outlook* reference case; the modification involves omission of new OCS lease sales starting in 2017. This modified reference case thus represents the No Sale Option for every program area. Removing the EIA's expectation of production from new OCS leasing allows investigation of alternative new OCS leasing scenarios within the EIA's broad energy market projection using *MarketSim*.

To simulate the effects of new production from leases issued under the 2017–2022 Program, BOEM adds anticipated OCS production according to the exploration and development (E&D) scenario from each program area to the oil and gas supply of the baseline (i.e., the No Sale Option in each program area), triggering a series of simulated price and quantity changes until each fuel market reaches equilibrium where supply equals demand. *MarketSim* uses price elasticities derived from NEMS runs and from other published elasticity studies (e.g., Dahl 2012, Serletis et al. 2010) to quantify the changes that would occur to prices and energy production and consumption over the 50-year period of production from the program area.

MarketSim also models oil, natural gas, coal, and electricity markets to account for substitution between alternate fuel sources. It incorporates feedback effects among the markets for substitute fuels using cross-price elasticities between the fuels. For instance, a gas price decrease from added supplies increases the quantity of gas demanded, which then decreases the demand for coal, which in turn decreases the price of coal thereby dampening the initial increase in the quantity of gas demanded. In order to more accurately depict these substitutions, each fuel's demand is decomposed into residential, commercial, industrial, and transportation uses with its own-price and cross-price elasticity specific to each submarket. Additionally, each fuel is modeled for up to eight components of supply (e.g., for the oil market, supply is modeled from domestic onshore, domestic offshore, Alaska, biofuels, other, and imports). This detail allows *MarketSim* to simulate changes in energy prices and the resulting substitution effects between fuels in the presence of changes in OCS oil and gas production. Additional details about how *MarketSim* models fuel substitutions across energy markets and sources are described in the *MarketSim* documentation (BOEM 2015c). Tables of the demand and supply elasticities used in the model are shown in the *MarketSim* documentation, *Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The 2015 Revised Market Simulation Model* (BOEM 2015c).

1.3.2.1 Recent Updates to the MarketSim Model

Since the publication of the *MarketSim* model documentation in December 2015 (BOEM 2015c), BOEM has made two refinements to the model, both of which are reflected in BOEM's assessment of the 2017-2022 Program. The first is an update of the baseline data included in the model, and the second is a revision of some of the model's supply elasticities. These changes are described in detail below.

1.3.2.1.1 Baseline Data

The previous version of *MarketSim* relied on baseline data obtained from a specially requested run of the EIA's NEMS delivered to BOEM in May 2015. *MarketSim* requires data from a specialized run of the NEMS model because the standard run produced for the EIA's Annual Energy Outlook (AEO) includes new OCS oil and gas leases in its projection of energy supply. In order for *MarketSim* to estimate the incremental impacts of new leases, all new OCS production must be excluded from the baseline. BOEM updated the baseline data in *MarketSim* using the outputs from a new specialized NEMS run developed by the EIA in August 2016. This update ensures that *MarketSim* will estimate energy market equilibriums that are consistent with recent developments in U.S. and international energy markets.

1.3.2.1.2 Elasticities

The majority of the default supply and demand elasticities in the *MarketSim* model rely on estimates from the peer-reviewed economic literature. However, for supply and demand categories without available elasticity estimates, the model relies upon elasticities derived from AEO projections. These elasticities are calculated as the change in production in response to a change in price observed between the low-price, high-price, and reference case projections in the EIA NEMS runs. In the previous version of *MarketSim*, these elasticities were derived from the projections in both the 2014 AEO and 2015 AEO. BOEM updated these derived elasticities using the low-price, high-price, and reference case projections from the August 2016 specialized NEMS runs provided by EIA.

Specifically, BOEM calculated three separate elasticities for each year between 2017 and 2040, based on the quantity and price differences between the low-price case and the reference case, the low-price case and the high-price case, and the reference case and the high-price case. Each of these annual elasticities was derived using the following formula:

$$\eta_t = \frac{\ln\left(\frac{Q_{A,t}}{Q_{B,t}}\right)}{\ln\left(\frac{P_{A,t}}{P_{B,t}}\right)}$$

Where η is the derived elasticity in year *t*, $Q_{A,t}$ and $Q_{B,t}$ represent the quantities supplied in year *t* for two separate cases (e.g. low-price and reference), and $P_{A,t}$ and $P_{B,t}$ represent the prices in year *t* for two separate cases. BOEM then averaged all of the annual elasticities across each year and combination of cases to derive a single average annual elasticity for each fuel and production category. BOEM excluded outliers from this average, which we defined as elasticity estimates with an inconsistent sign (i.e., a positive number for a demand elasticity or a negative number for a supply elasticity) and estimates greater in magnitude than the 95th percentile estimate. If the final estimated elasticity based on the NEMS data was unrealistic even after accounting for outliers, BOEM reverted back to the value from the previous version of *MarketSim*.

Overall, BOEM updated six of the 26 default supply elasticities in *MarketSim* through this process. These updates are reported in Table 1-1: Changes to Supply and Demand Elasticities. BOEM also updated 1 demand elasticity out of the 42 included in the model. The previous version of *MarketSim* included an elasticity of demand for U.S. exports of refined petroleum products of -0.16, derived from AEO 2014 data. BOEM estimated a revised elasticity of -0.08 based on the August 2016 NEMS data.

Table 1-1: Changes to Supply and Demand Elasticities

Supply or Demand	Fuel	Supply or Demand Category	Elasticity from Previous Version of MarketSim	New Elasticity
Demand	Oil	U.S. exports of refined petroleum	-0.08	-0.16
Supply	Oil	Lower 48 Onshore	0.51	No change
		Lower 48 Offshore	0.51	No change
		Alaska	0.51	No change
		Other	0.51	No change
		Biodiesel	0.24	No change
		Rest of World	0.4	No change
		Canadian Pipeline Imports	1	No change
	Natural Gas	Lower 48 Conventional	0.29	No change
		Lower 48 Unconventional	1.6	No change
		Alaska	0.29	No change
		Offshore	0.29	No change
		Other	0.51	No change
		Pipeline Imports	0.34	0.52
		LNG Tanker Imports	1	No change
	Electricity	Oil	0.8	0.46
		Natural Gas	1	No change
		Coal	1.41	1.07
		Nuclear	2.06	1
		Other Electric	1	No change
		Hydro	1.1	0.13
		Wind Onshore	1	No change
		Wind Offshore	1	No change

Supply or Demand	Fuel	Supply or Demand Category	Elasticity from Previous Version of MarketSim	New Elasticity
		Solar	1.24	No change
		Imports	0.87	0.06
	Coal	Domestic	1.86	No change
		Imports	1	No change

1.3.3 Offshore Environmental Cost Model

BOEM employs the OECM to estimate both the quantifiable environmental and social costs that would result from OCS activities in each program area and the costs that would occur without new leasing (i.e., the No Sale Option).

The OECM is a Microsoft Access-based model that uses the levels of OCS activity from the E&D scenarios in the NEV calculation in the 2017–2022 PFP and the associated environmental impact statement (EIS), the *2017–2022 OCS Oil and Gas Leasing Program Final Programmatic Environmental Impact Statement* (herein referred to as the "Final Programmatic EIS", BOEM 2016b) along with the energy market substitutions from *MarketSim* to calculate net environmental and social costs. The OECM analysis evaluates six environmental and social cost categories for each program area: air quality, ecological, recreation, property values, subsistence harvests, and commercial fisheries. The impacts from each category are summed to derive the environmental and social costs of the program. These costs are then compared to similar costs calculated from the No Sale Option. The two cost categories that apply to the No Sale Option costs are discussed separately.

1.3.3.1 Program Environmental Cost Categories

Air Quality: The monetary value of the human health, agricultural productivity, and structural damage caused by emissions generated by oil and gas activity.

- Emissions are calculated based on activity levels and the air quality impacts are determined by the dispersion and monetization estimated by the Air Pollution Emission Experiments and Policy (APEEP) analysis model (Muller and Mendelsohn 2006, Muller 2014).
- Air emission factors were updated for the 2015 Revised OECM. These new factors are based on a more in-depth analysis of air quality data. Emissions factors are revised for offshore and onshore activities, including for sources pertaining to the *MarketSim* substitutions. Additionally, air quality impacts related to onshore pipeline construction are estimated for the Chukchi Sea Program Area, where the E&D scenario assumes a 284-mile onshore pipeline is constructed to transport oil from the Chukchi Sea to the Trans-Alaska Pipeline System (TAPS).
- Tables of the specific emissions factors are included in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a).

Ecological: Restoration cost for habitats and biota injured by oil spills.

- The model uses a habitat equivalency analysis (HEA) approach in which the cost of creating the equivalent habitat area measures the dollar damages assigned to the lost ecosystem services.
- This application is consistent with the standard economic view of natural resources as assets that provide flows of ecosystem services valued by society, as demonstrated by the willingness to pay for their protection.
- Changes in the quality or quantity of these services (e.g., due to ecosystem injuries caused by non-catastrophic oil spills) have implications in terms of the value of the benefits they provide.

1.3.3.2 ***Program Social Cost Categories***

Recreation: The loss of consumer surplus that results when oil spills interfere with recreational offshore fishing and beach visitation.

- Estimates are based on the use value of recreational fishing and beach visitation because they capture the primary recreational services of coastal and marine resources that would be affected by OCS activity.
- These are the services for which relevant data are generally available on a consistent, national basis.

Property Values: Impacts of the visual disturbances caused by offshore oil and gas platforms and losses in the market value of residential properties caused by non-catastrophic oil spills.

- Impact is defined as the annual loss in potential rent from residential properties resulting from visual disturbances from platforms and damage from oil spill events.
- The property damage from oil spills is calculated as the product of the property value per linear meter of beach, the after-tax discount rate, the fraction of year taken up by the event, and the length of oiled shore.

Subsistence Harvests: The replacement cost for marine subsistence species killed by non-catastrophic oil spills in Alaska.

- The model assesses the impact of OCS oil and gas activities on Alaska harvests by estimating non-catastrophic oil spill-related mortality effects among general subsistence species.
- The model assumes that all organisms killed by oil spills would have been harvested for commercial or subsistence purposes, determines the subsistence component of this lost harvest, and calculates a replacement cost.

Commercial Fisheries: The loss from extra fishing effort imposed by area preemption due to the placement of oil and gas infrastructure (platforms and pipelines).

- The model assumes that there will be buffer zones around platforms. In most cases, the buffer zones will be a circle with a radius of 805 meters (0.5 miles).
- The model also assumes that the total amount harvested is unaffected by oil and gas infrastructure since nearly all fisheries in OCS waters are managed with annual catch limits set below the harvestable biomass. However, the buffer zones force the harvest activities to less efficient fishing areas.
- Non-catastrophic oil spill impacts are likely to result in temporary fishery closures. Since most fisheries are managed through catch limits, a temporary closure will still give the industry ample opportunity reach the catch limit.

1.3.3.3 No Sale Option Impact Categories

From the energy substitutes under the No Sale Option, the OECM has identified two particular responses as significant enough to monetize. These include (1) the increase in oil and natural gas imports delivered to the U.S. from overseas tankers; and (2) the increase in the onshore production of oil, natural gas, and coal within the United States. The increase in imports and domestic production result in air quality and oil spill impacts.

Air Quality

- The model assesses the air quality impacts for increased oil and natural gas tanker imports from (1) tanker cruising, (2) unloading, (3) volatile organic compound (VOC) losses in transit (oil tankers only), and (4) ballasting (oil tankers only). Monetized emissions are only calculated for the portion of the trip in which the tankers would be within U.S. waters.
- The model estimates the increased air emissions from the increase in onshore production of oil, natural gas, and coal using a set of emission factors specific to fuel type and applying a dollar-per-ton value which represents the monetized costs of onshore emissions. The dollar-per-ton estimates were calculated using the APEEP model.

Tanker Oil Spill Risks

- To calculate the costs associated with the increased oil spill risk from increased oil tanker deliveries, the model uses the same spill probability and spill distribution factors as used in calculating program risks in each program area.
- The model then applies this derived value to the cost calculations used for the categories driven by oil spill volumes discussed above (i.e., ecological, recreation, property values, subsistence harvests).

While the OECM captures several significant cost categories, not all impacts are catalogued and monetized in the OECM. See Chapter 3, Non-monetized Impacts, for more qualitative analysis on these impacts as well as the document *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised OECM* (BOEM 2015b).

The OECM is continuously updated to improve the estimation of existing cost categories as well as impacts currently outside the scope of the model as new data and information becomes available. For more detailed information on the specific methodology used to calculate current cost categories, refer to *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a).

1.3.4 Assumptions

Considerable uncertainty surrounds future production from OCS submerged lands and resulting impacts on the economy. A broad range of future conditions can result from a lease sale schedule. To be useful, an analysis must be specific and realistic, which is a challenge in the face of uncertainty. Price expectations play an especially important role in estimating the value of the PFP anticipated production. For instance, the industry will be much more likely to develop hydrocarbon resources in frontier areas if it expects future oil prices to be high. Conversely, there will be less interest in frontier areas when price expectations remain low. Despite a broad range of future conditions that can result from activities associated with the program, BOEM strives for consistency by using standard input assumptions. The Final Programmatic EIS analysis accompanying the PFP uses the same set of economic, exploration and development assumptions as the net benefits analysis.

Assumptions for the following, each explained in more detail below, are used in the PFP analysis:

- oil and natural gas prices
- finding and extraction cost assumptions
- discount rate
- anticipated production and activity scenarios.

1.3.4.1 Oil and Natural Gas Price-Level Assumptions

Leasing from the 2017–2022 Program enables new exploration, development, and production activity for a period of more than 50 years. Although oil prices can experience a high degree of volatility during this period, BOEM assumes three level price scenarios in which the inflation-adjusted, or "real," prices for oil and gas remain constant to allow decision makers to more easily envision and compare the range of possible production, benefits, and costs if prices rise or fall. Owing to different timing requirements among program areas, use of variable prices in the analysis would make it difficult for the decision makers to separate out the impacts of forecast price changes from the underlying differences in program areas. For this reason, the PFP analysis includes resource and incremental net benefit estimates for each of the three level price scenarios shown in Table 1-2: Proposed Final Program Price Scenarios. These price cases are not meant to imply or represent price expectations, forecasts, or even upward and lower bounds of possible prices. These price cases were selected to encompass a reasonable range of activity levels given possible oil and gas prices over the life of the 2017–2022 Program. These price cases are supported by current price projections from respected price forecasts. For example, EIA provides low, reference, and high oil price cases in their Annual Energy Outlook which support BOEM's price cases as providing three reasonable price points over the wide array of possible future prices.

The price scenarios used for the PFP are the same as the Proposed Program. Price scenarios were initially revised in the Proposed Program from the Draft Proposed Program (DPP), which used slightly higher low and mid-price oil prices ($60 and $110, respectively) and higher natural gas prices for the low-, mid-, and high-price scenarios ($4.27 per mcf [thousand cubic feet], $7.83 per mcf, and $11.39 per mcf, respectively). BOEM revised its price scenarios from the DPP based on recent trends in oil prices. These price scenarios are meant to provide a representative range of possible oil prices, which are then used to illustrate the effects of low, mid-, and high oil prices on leasing, exploration, and development activities on program options.

Table 1-2: Proposed Final Program Price Scenarios

Price Scenario	Oil (per bbl)	Gas (per mcf)
Low Price	$40	$2.14
Mid-Price	$100	$5.34
High Price	$160	$8.54

Key: bbl = barrel of oil; mcf = thousand cubic feet

The lower natural gas prices were revised given the major changes in energy-equivalent prices for natural gas and oil in recent years. In previous Program analyses, the ratio of the price of natural gas to oil for the same heat content equivalency factor (British thermal units [Btu]) was 40 percent, but actual prices in recent years prompted BOEM to revise this assumption and use a 30 percent factor for the PFP.

1.3.4.2 Cost Assumptions

If resource prices increase significantly, impacts on post sale oil and gas activities are not immediately felt due to long lead times needed to explore for resources and new infrastructure required to support higher activity levels. In addition, large increases in resource prices create additional competition for existing drilling rigs and investment dollars from other parts of the world, raising the cost of exploration, development, and production that in turn dampens the production boost from increased resource prices. Based on a historical analysis, BOEM assumes a cost-price elasticity of 0.5 to calculate the incremental NEV for each program area price scenario. In other words, BOEM assumes the costs of oil and gas exploration and development change in half the proportion as the change in oil prices across the scenarios.

1.3.4.3 Discount Rate

Based on guidance from OMB Circular A-4, a real discount rate of 3 percent is used for determining the present value of all net benefits analysis calculations. A discount rate of 3 percent is considered the appropriate rate by OMB for the "social rate of time preference." This simply means the rate at which "society" discounts future consumption flows to determine their present value. In the case of determining applicable economically recoverable resource amounts, shown in Table 1-3: Proposed Final Program Anticipated Production Estimates, various private rates of return were employed consistent with the level of risk in each program area to estimate the amount of oil and gas resources that would be profitable for the private sector to lease and explore.

1.3.4.4 Anticipated Production

Anticipated production is the estimated quantity of oil and natural gas expected to be produced as a result of the lease sales included in the PFP. The net benefits analysis uses anticipated production as a key empirical input to calculate the NEV of future production streams. As described in Section 5.3 of the PFP, the estimates of anticipated production are based on the undiscovered economically recoverable resource estimates from the *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2016* (BOEM 2016c; referred to in this document as the "2016 National Assessment").

Table 1-3: Proposed Final Program Anticipated Production Estimates shows anticipated production estimates for program areas included in the PFP decision document under the three sets of level resource price scenarios, and assuming application of the same fiscal terms and conditions employed in lease sales held under the 2012–2017 Program. The time of production ranges between price cases and program areas, but is generally between 50 and 70 years.

Table 1-3: Proposed Final Program Anticipated Production Estimates

Location	Oil (Million barrels)			Gas (Bcf)			BOE (Million barrels)		
	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price
Beaufort Sea	*	2,295	3,673	-	4,029	6,447	-	3,012	4,820
Chukchi Sea	*	2,644	4,231	-	1,116	1,785	-	2,843	4,548
Cook Inlet	84	209	335	37	93	149	90	226	362
Gulf of Mexico	2,105	3,531	5,593	5,470	12,011	22,122	3,079	5,668	9,529
TOTAL	2,189	8,680	13,831	5,507	17,250	30,503	3,169	11,749	19,259

Key: BOE = barrel of oil equivalent, Bcf = billion cubic feet
Note: Low oil and gas price cases in the Chukchi and Beaufort Seas represent an "Exploration only" scenario due to negligible undiscovered economically recoverable resources.

In addition to estimating the anticipated production that could result from the OCS program, BOEM, through its E&D scenarios, estimates the associated activities and facilities that are required for the exploration and development of the anticipated production. These activities cause both private and public costs, which are incorporated into the net benefits analysis.

These estimates of anticipated production are used for both the net benefits analysis and the Final Programmatic EIS. To avoid underestimating the environmental impact in the Final Programmatic EIS, the estimates and resulting net benefits estimates are likely an overestimate of the production and resulting level of activity that might occur in each region.

1.4 INCREMENTAL NET ECONOMIC VALUE

The first step in the net benefits analysis is calculation of the incremental NEV associated with lease sale(s) in each program area. Overall, incremental NEV measures an element of social value that may be generated by lease exploration, development, and production activities under certain assumptions about oil and gas prices, resources, etc. The approach to determining incremental NEV is similar to customary cash flow modeling, except that the calculations are done at a highly aggregated level and discounted at the social rate.

As an update to the previous *Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012–2017* (BOEM 2012a), the incremental NEV analysis for the 2017-2022 PFP subtracts the benefits of the energy substitutes attributable to the No Sale Option from the Program NEV. This new adjustment accounts for the loss of economic opportunities (i.e., the NEV associated with the domestic energy market substitutes) and is more consistent with the calculation of incremental environmental and social costs explained in the next section. The "incremental" analysis thus considers the Program benefits after accounting for economic opportunities in the absence of the Program.

For the incremental NEV calculation, aggregate revenues are the anticipated production described in Section 1.3.4.4, Anticipated Production, multiplied by the price levels discussed in Section 1.3.4.1, Oil and Natural Gas Price-Level Assumptions. Aggregate costs of equipment, labor, transportation, etc. are then subtracted from aggregate revenues. The timing and level of activities are, as mentioned above, described in the E&D scenarios. For consistency, the NEV estimates are based on the same schedules of exploration, development, and production activities used in the OECM to obtain the environmental and social costs for each program area and, again, in the Final Programmatic EIS to evaluate the impact of that activity on the human environment.

The incremental NEV is based on discounting (at a social rate of 3 percent) the revenue from the new OCS oil and gas produced minus the costs of exploration, development, and production. In contrast, the underlying resource assessment for economically recoverable resources is conducted using private discount rates appropriate for the risk and return expected in the oil sector. This is appropriate because the incremental NEV analysis starts by identifying the oil and gas production amounts BOEM expects companies will regard as profitable (i.e., classified as economically recoverable resources). For that amount, the analysis subsequently weighs the cost of labor, equipment, etc. needed to produce those resources against the value of the produced oil and natural gas. To the extent these production costs reflect opportunity costs of dedicating the labor, equipment, etc., to the OCS activities instead of to alternative uses for those inputs, this provides a measure of social value.

The incremental NEV analysis alone does not ensure that the resulting program area measures represent their maximum values. Decisions related to sale configurations within a program area are postponed until close to the sale date. However, it is important to know now whether there appears to be at least some acreage within each of the areas being considered for inclusion in the Five-Year Program that appears to be more valuable if leased in the near term than five or more years from now. Accordingly, BOEM conducts a "hurdle price" analysis on lease sale timing in Chapter 10, Assurance of Fair Market Value, in the PFP. The Fair Market Value Analysis is further discussed in Chapter 4 of this Economic Analysis Methodology document.

The general equation for calculating the NEV for a program area is shown in Figure 1-2 as follows:

Figure 1-2: Calculation of Program NEV

Additionally, the first box in Figure 1-2 can be expressed in mathematical notation:

$$NEV_i = \sum_{t=1}^{n} \left[\frac{(AG_{it} * PG_t) + (AO_{it} * PO_t) - C_{it}}{(1+r)^t} \right]$$

Where:

NEV_i = the estimated net present value of gross economic rent in the ith program area
AG_{it} = the anticipated production of natural gas from program area i in year t
PG_t = the natural gas price expected in year t
AO_{it} = the anticipated production of oil from program area i in year t
PO_t = the oil price expected in year t

C_{it} = a vector of exploration, development, and operating costs
r = a social discount rate
n = years from start of the program until the end of last production from leases sold within the Five-Year Program timeframe

To determine the No Sale Option (second box in Figure 1-2), BOEM compares baseline *MarketSim* results with results calculated using production from the program area to determine the quantity and type of fuel use that would occur if no new leasing were permitted in the OCS program area.[7] The energy market substitutions must be factored into the net benefits analysis because the selection of the No Sale Option in one or more program areas will lead to slightly higher oil and gas prices, which will result in a slight reduction in demand and additional domestic production, increased imports, and fuel switching to meet the continuing demand for oil and gas resources.

Table 1-4: Substitute Energy Results of the No Sale Options shows the energy market substitutions expressed in barrel of oil equivalent (BOE) percentages that would occur from excluding all program areas.[8] The energy market substitutes are shown under each of the three price scenarios and with an average of the three cases. The energy substitutes show, on a per BOE basis, how forgone OCS production is replaced. The percentage replacements represent the percentage of forgone production which is replaced by a particular substitute energy source. For example, if the No Sale Option were chosen in a particular program area, 7 percent of the production which could have been produced from OCS leases issued in that program area as a result of this program would not be replaced by another energy source and would instead represent reduced consumption as a result of the slightly higher market prices resulting from the decision to exclude the area from the program.[9]

The substitutions in the three price cases vary based largely on the mix of oil and natural gas production anticipated from the OCS program. In general, the majority of oil produced on the OCS is replaced by oil imports and the majority of the natural gas is replaced by onshore production. The following calculations on the type of substitutions are not included in Table 1-4: Substitute Energy Results of the No Sale Options, but are provided for additional context. Under the mid-price case with all program areas included, the total offshore oil production over the life of the program is estimated to be 48.4 BBOE. If the No Sale Option were selected in each program area, the offshore production baseline is projected to be only 39.8 BBOE over the life of the program. The difference of 8.6 BBOE in forgone new OCS oil production would be replaced by the energy substitutes. To determine the percentage of forgone OCS oil production replaced by increased oil imports, BOEM subtracts oil imports anticipated under the PFP (46.4 BBOE) from the oil imports expected in the baseline (54.0 BBOE) and divides by the difference in total forgone OCS production [(54.0 – 46.4) BBOE /8.6 BBOE], which equals 0.88 or 88 percent. Compared to all production (i.e., forgone oil and natural gas), the substitution of oil imports accounts for approximately 65 percent of total forgone OCS production [(54.0 – 46.4) BBOE / 11.8 BBOE].

[7] *MarketSim* is a national model and does not look at variation in gas prices in different regions.
[8] The actual percentages will vary between program areas depending upon whether a particular area is gas or oil prone and the likely source of substitute energy sources in the absence of a particular program area.
[9] It is important to note that the reduced consumption represents 7 percent of the forgone energy production, not of any subset of U.S. energy demand. If the No Sale Option were selected in each program area, the *MarketSim* calculations indicate that the reduced consumption would only represent a 0.22 percent decrease in baseline U.S. natural gas demand and a decrease of 0.04 percent in baseline U.S. oil demand. Additional context on these figures is provided in Section 3.1, Greenhouse Gas Emissions.

Table 1-4: Substitute Energy Results of the No Sale Options

Energy Sector	Percent of OCS Production Replaced			
	Low	Mid	High	Average
Onshore Production	28%	24%	26%	26%
Onshore Oil	3%	4%	3%	3%
Onshore Gas	25%	20%	22%	22%
Production from Existing State/Federal Offshore Leases	1%	1%	1%	1%
Imports	61%	65%	63%	63%
Oil Imports	60%	65%	63%	63%
Gas Imports	<1%	<1%	<1%	<1%
Coal	<1%	<1%	<1%	<1%
Electricity from sources other than Coal, Oil, and Natural Gas	1%	1%	1%	1%
Other Energy Sources	3%	3%	3%	3%
Reduced Demand/Consumption	7%	7%	7%	7%

Note: The percentages in this table represent the percent of forgone production with the selection of the No Sale Option that is replaced by a specific energy source (or in the case of reduced demand/consumption not replaced). For example, if the No Sale Option were selected in the Cook Inlet, on average 26 percent of the anticipated production which would have been produced from that program area if leasing had occurred would be replaced with onshore oil and natural gas production.

Alternatively, for natural gas, the majority of the forgone OCS production is replaced with onshore production. With all of the program areas included in the program, total offshore natural gas production is estimated to be 17.3 BBOE which is 3.1 BBOE greater than under the baseline with no new OCS production of 14.2 BBOE over the life of the program. BOEM subtracts the onshore production anticipated under the PFP (514.6 BBOE) from the onshore production expected in the baseline (517.0 BBOE) and divides by the difference in total forgone OCS natural gas production [(517.0 – 514.6) BBOE / 3.1 BBOE], which equals 0.77 or 77 percent (note that numbers do not compute exactly due to rounding). Compared to all OCS production, onshore natural gas production contributes 20 percent in the mid-price case [(517.0 – 514.6) BBOE / 11.8 BBOE].

On an aggregate basis, these estimates indicate that approximately 93 percent of the likely new OCS production would be replaced by increased production from other fuel sources, generating the attendant environmental and social costs for that substitute activity. The remaining forgone OCS production is not replaced, but rather, the slightly higher market clearing prices for oil and gas are estimated to reduce quantity demanded by almost seven percent of the forgone OCS production.

Based on *MarketSim* model runs for the Program scenario (in contrast with the No Sale Option), BOEM estimates that approximately 30 percent of forgone energy substitutes will be replaced with domestic sources of energy (as shown in Table 1-4: Substitute Energy Results of the No Sale Options, 26 percent from onshore production, 1 percent in existing offshore production, less than 1 percent from coal, and 3 percent from electricity and other energy sources). To account for the NEV of these domestic sources, NEV estimates from the OCS program proposal are reduced by 30 percent. The other 70 percent of OCS production is either replaced by imports or forgone as a result of reduced consumption in the face of higher oil and gas prices. BOEM uses the conservative assumption that the NEV from the domestic substitute energy sources will be equivalent to the NEV from OCS production. This represents an overestimate of the NEV from the energy substitutes as it would almost certainly be less than that from the OCS since the energy substitutes are only necessary given a policy decision not based on economics. The remaining value is the incremental NEV. Table 1-5: Incremental Net Economic Value by Program Area, shows the incremental NEV for each program area.

Table 1-5: Incremental Net Economic Value by Program Area

Program Area	Program NEV			No Sale Option NEV			Incremental NEV		
	Low	Mid-	High	Low	Mid-	High	Low	Mid-	High
	($ billions)								
Beaufort Sea	-2.46	25.73	115.87	-	8.13	36.59	-2.46	17.61	79.28
Chukchi Sea	-0.42	58.92	191.13	-	18.61	60.39	-0.42	40.32	130.78
Cook Inlet	0.15	6.86	19.04	0.05	2.17	6.01	0.10	4.69	13.03
Gulf of Mexico	3.51	71.60	248.44	1.11	22.61	78.45	2.40	48.99	169.98

Notes: All values are discounted at a real discount rate of 3 percent. The low-price case represents a scenario under which inflation-adjusted prices are $40 per barrel for oil and $2.14 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $100 per barrel and $5.34 per mcf. Prices for the high-price case are $160 per barrel and $8.54 per mcf. Given current information, no production is expected from either Arctic program area at the low-price case, whether from one or two sales; therefore NEV is assumed to be zero. If exploration occurs, NEV could be either negative—if no production results—or positive—if successful exploration leads to production.

BOEM determines the incremental NEV for three separate flat real dollar price cases assumed in the development of the E&D scenarios and corresponding production deemed likely from each of the program areas. Table 1-5: Incremental Net Economic Value by Program Area, summarizes these incremental NEV estimates.

The incremental NEV generated as a result of the market value of production exceeding the cost of exploration, development, and production is captured in part by the Federal government and accrues to the general public in the form of leasing revenues (i.e., cash bonuses, rentals, and royalties) and corporate income tax revenues paid by lessees. A portion of the incremental NEV is retained by lessees as economic rents in the form of corporate profits. Conceptually, only the U.S. share of the incremental NEV contributes to domestic welfare, so the net benefits analysis calculation reported here includes only the likely domestic share as determined in the remainder of this chapter.

The Federal share of the incremental NEV estimates shown above in Table 1-5: Incremental Net Economic Value by Program Area, ranges from 48 to 83 percent for the different program areas under the mid-price case. A recent study done for BOEM and the Bureau of Land Management found a similar range of Government take (between 64 and 79 percent) under the current U.S. offshore fiscal system from representative future OCS projects (BOEM and BLM 2011). The bulk of incremental NEV is collected by the domestic fiscal system on behalf of U.S. taxpayers so all of it contributes to domestic net benefits.[10]

The private sector share of incremental NEV that flows to U.S. citizens also contributes to domestic net benefits. While a portion of the private share of the incremental NEV derived from new OCS production flows to non-U.S. citizens through profits going to foreigners holding shares in U.S. oil companies, counter flows go to U.S. citizens holding shares in the foreign oil companies active on the U.S. OCS.[11] BOEM does not have information on the nationality of shareholders in OCS operators, but aggregate data available show U.S. holdings of foreign equities is slightly higher ($6.75 trillion) than foreign holdings of U.S. equities ($6.36 trillion) (DOT 2015). BOEM has no reason not to expect the same pattern to hold for those companies that win new leases under the program, so as a simplifying assumption BOEM assumes foreign shareholders in U.S. oil companies and U.S. shareholders in foreign oil companies active on the OCS balance each other. That leaves only the need to net out the private share of NEV going to foreign shareholders in these foreign oil companies. As a rough proxy for the share of foreign beneficial owners of activities on the U.S. OCS, BOEM uses EIA's estimate that 13 percent of U.S. domestic oil supply and 10.6 percent of U.S. domestic gas supply are produced by subsidiaries of foreign oil companies (EIA 2011). Note that lease ownership continually changes and could be higher than these percentages. Applying these foreign interest shares of each product to the average 16 to 54 percent private sector share of NEV, BOEM finds that about 95 percent of total NEV generated by the Program accrues to U.S. interests. Accordingly, BOEM includes that adjustment in the Program NEV reported above for each program area. On the other hand, foreign shareholders invest a considerable amount of money in the U.S. economy to buy their shares (to obtain the profits). It would be difficult to estimate those investments, and BOEM has not reduced national costs to account for this inflow of capital.

BOEM notes that the incremental NEV is different from the assessment of the regional economic impact of OCS activities measured in the Chapter 8, Equitable Sharing Considerations, in the PFP. A regional economic impact analysis measures the gross value produced by, or the relative importance of, different industries or sectors, such as oil and gas production, recreation, etc., within a local or regional economy. But that approach does not reveal the contribution to social wellbeing from those activities because it does not consider the alternative activities forgone to provide these gross values. Accordingly, the incremental NEV concept of value is a more appropriate measure to compare the costs and benefits of policy alternatives.

1.5 Incremental Environmental and Social Costs

Whereas the incremental NEV analysis considers the private costs incurred by the firms that explore for and develop OCS oil and gas resources, society also incurs external environmental and social costs from

[10] The Government tax and leasing revenue portion of the NEV calculation does not separate out special incentives or subsidies. Such Government subsidies do not change the NEV, only how that NEV is distributed between the Government and producing firms. Special tax considerations such as the depreciation of tangible and intangible expenses similarly do not affect total NEV, only the timing and magnitude of payments between producers and the Government. Subsidy effects also occur in replacement sources that would be used under the No Sale Option, so their omission in this relative analysis merely assumes that these subsidies are proportionally equal in the two supply sources. Subsidies and taxes that affect downstream consumption, such as the gasoline tax, are not considered in the net benefits analysis because they are beyond the scope of the analysis and are not within the authority of the Secretary to control.

[11] All companies that operate on the OCS are American corporations, but they may be subsidiaries of foreign parent companies.

OCS activities and facilities associated with offshore oil and gas production. These types of costs also arise from substitute sources of energy that would be used in the absence of this new OCS production.

The external costs arise from environmental (e.g., pollution effects on human health or agricultural productivity) and social (e.g., oil spill effects on recreational fishing or beach use) damages which can occur during the exploration, development, production, and transportation of OCS oil and gas resources developed under the Program or from their No Sale Option replacements. The external costs reflect actions taken by lessees under applicable regulations to prevent oil spills, mitigate air pollution, and avoid accidents. The private costs incurred to mitigate these external effects are included as avoidance and abatement costs in the incremental NEV analysis.

1.5.1 OECM Calculations

The OECM calculates the environmental and social costs of OCS activities for the six categories listed in Section 1.3.3, Offshore Environmental Cost Model. The OECM uses the parameters set forth in the E&D scenario to estimate the location of non-catastrophic spills. The OECM inputs this information into the Spill Impact Model Application Package (SIMAP), which uses regression analysis to estimate the physical damage from oiling.[12] Then, using impact equations developed for the cost categories of ecological, recreation, property values, and subsistence use effects, the OECM employs the SIMAP regression outputs and anticipated spill size and location data to estimate costs. Due to the unique characteristics of the air quality and commercial fishing cost categories, the OECM employs the output from external modules to estimate air quality and non-catastrophic oil spill effects associated with OCS production in these two categories.

Table 1-6: OECM Cost Categories and Estimates for Proposed Final Program Areas, shows the OECM estimates for the six environmental and social cost categories that make up the external costs for the mid-price case of the five program areas. The costs of both the PFP options and No Sale Option are included in Table 1-6. For the No Sale Option, OECM estimates those costs that occur within the U.S. boundaries including territorial waters (i.e., the production and transport to U.S. waters of energy which is imported to the U.S. is not included, but the transportation within U.S. waters to port is included).

The OECM is not designed to represent impacts from global climate change, catastrophic events, or impacts on unique resources such as endangered species.

[12] SIMAP is an oil spill impact modeling system providing detailed predictions of the three-dimensional trajectory, fate, impacts and biological effects of spilled oil.

Table 1-6: OECM Cost Categories and Estimates for Proposed Final Program Areas

OECM Cost Category	Program Costs	No Sale Option Costs
	$ millions	
Environmental Costs		
Air quality	4,432	17,879
Ecological impacts	3.08	5.35
Social Costs		
Recreation	221	243
Property values	0.16	1.01
Subsistence use	4.89	0.01
Commercial fishing	0.06	0.00

Notes: All values are discounted at a real discount rate of 3 percent. These values are the OECM results for the mid-price case with prices of $100 per barrel and $5.34 per mcf. Results are shown at the mid-price case for demonstration purposes. For the low and high price cases, the OECM results are proportionally smaller and larger, respectively.

The Final Programmatic EIS (BOEM 2016b) discusses global climate change, catastrophic events, and impacts on unique resources. The impacts of catastrophic spills are further discussed and analyzed in Chapter 2, Catastrophic Oil Spills of this methodology document. Two separate reports, *Economic Inventory of Environmental and Social Resources Potentially Impacted by a Catastrophic Discharge Event within OCS Regions* (BOEM 2014a), and *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development - Volume 2: Supplemental Information to the 2015 Revised OECM* (BOEM 2015b) discuss information on resources at risk and potential impacts from a catastrophic oil spill. Regarding climate change, GHG emissions and the social cost of carbon are discussed in the separate report, *OCS Oil and Natural Gas: Potential Lifecycle Greenhouse Gas Emissions and Social Cost of Carbon* (BOEM 2016a).

1.5.1.1 OECM Oil Spill Modeling

The environmental effects of non-catastrophic oil spills and the costs associated with those effects vary widely depending on variables such as the amount and type of oil spilled, the location of the spill, whether the spill hits shore, the sensitivity of the ecosystem affected, weather, season, and so forth. While it is not possible to deal with all these variables, information on the environmental and social costs associated with past oil spills have been relatively well documented so there is a reasonable basis for oil-spill risk and cost modeling in the literature.[13] The impact risk of an oil spill includes both the probability of spill incidents of various types occurring and the consequences of those incidents.

Spill Impact Risk = probability of spill X impacts of spill

Spill impact risk is the combination of both the likelihood a spill will occur and the likely sizes and resulting impacts of spills that do occur. The likelihood of a spill is measured as the historic ratio of the amount spilled to the amount produced. The analysis performed for the PFP uses aggregate estimates for all the spills that the model identifies as likely from the E&D scenario and anticipated production. The model also includes the oil spill risk from tankers transporting oil from offshore to onshore and from

[13] Oil spill information for the Arctic is based on SIMAP and earlier type A models which can be designed for both cold and warm water (French et al. 1996).

Alaska to the west coast in measuring the impacts of the Program. For tankers carrying oil imported to the U.S under the No Sale Option, the analysis applies the same spill risks as used for tankers transporting crude oil from Alaska to the west coast of the contiguous 48 states. The spill rates and sizes used in the model are based upon OCS spills from 1996–2010 of less than 100,000 barrels (BOEM/BSEE 2012). Data from that period captures the non-catastrophic spill rates experienced during the modern deepwater era of offshore drilling. New technologies and safety procedures make the non-catastrophic oil spill rates from 1996–2010 more representative of future activity than those calculated over a longer historical period.

Impacts of a spill depend on the spill size, oil type, environmental conditions, present and exposed resources, toxicity and other damage mechanisms, and population/ecosystem recovery following direct exposure. OECM uses the existing and well-documented SIMAP (French-McCay 2004, French-McCay 2009), to project consequences associated with a matrix of potential conditions. Region-specific inputs include habitat and depth mapping, winds, currents, other environmental conditions, chemical composition and properties of the oils likely to be spilled, specifications of the release (amount, location, etc.), toxicity parameters, and biological abundance.

Spills could occur in the context of OCS oil and gas exploration and development or in the context of imports that might serve as substitutes to OCS production. The SIMAP summarizes data that quantify areas, shore lengths, and volumes where impacts would occur with regression equations to simulate spills of varying oil types and sizes in each of the planning areas under a wide range of conditions. The results of these equations are then applied within the OECM. The oil spill modeling approach cannot and does not try to measure the effects of any individual spill.

The spill rates and sizes in the OECM also do not include large, catastrophic spills which are infrequent and unexpected to occur as a result of this program. The OECM is not designed to address catastrophic spills because the oil spill modeling that forms the basis of the OECM is conducted through SIMAP, which models smaller surface releases. Subsurface releases likely in a catastrophic spill would have very different oil behavior and fate than what is available and included in the current model.[14] As a result, if a catastrophic spill volume was included in the model, the model would treat the large volume spilled as a series of smaller spills thereby producing an unrealistic estimate. Doing so would mask the cost of the smaller, more probable events. To allow both types of spills to be accurately calculated, the potential effects of catastrophic spills related to the PFP are discussed in Chapter 2 of this document.

1.5.1.2 OECM Air Emissions Modeling

The OECM estimates the level of air emissions associated with drilling, production, and transportation for any given year based on the 2017–2022 PFP E&D scenarios and leasing schedule. Oil and gas exploration and development will lead to emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), VOCs, particulate matter, and other air pollutants that may adversely affect human populations and the environment. To account for these effects, the OECM includes an air quality module that calculates (1) the emissions—by pollutant, year, and program area—associated with a given E&D scenario and

[14] Data on subsurface releases are not included in the OECM model because they generally are not available at this time. Large subsurface spill studies are currently in development.

production rate and, (2) the monetary value of the environmental and social damage caused by these emissions, estimated on a dollar-per-ton basis. The model estimates emissions based on a series of emissions factors derived from BOEM data and converts the modeled emissions to monetized damages using impact-per-ton values derived from a modified version of the APEEP model (Muller and Mendelsohn, 2006).[15]

Emissions factors for Gulf of Mexico (GOM) activity were derived from the BOEM Gulfwide Offshore Activities Data System (GOADS) software. For Alaska, the emissions are estimated based on emissions data from the Environmental Protection Agency (USEPA) and oil producers for the equipment expected to be used. Emissions are scaled based on continual activity for the maximum amount of time the equipment might be in use. For tankers carrying oil imported to the U.S. under the No Sale Option, the analysis applies the same emission factors used for tankers transporting crude oil from Alaska to the West coast of the contiguous 48 states.

Emission factors for onshore oil production for the contiguous United States under the No Sale Option scenario are based on the Western Regional Air Partnership's (WRAP) emissions inventory for oil production activities in twelve western states. These states include Alaska, Arizona, California, Colorado, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, and Wyoming (WRAP 2009). Because the WRAP inventory does not separate onshore and offshore emissions and the database is being used specifically for calculating onshore emissions, Alaska and California were excluded. The OECM's emissions factors for onshore gas production were derived from emissions data from the Department of Energy's (DOE's) National Energy Technology Laboratory, the USEPA, and the World Resources Institute and gas production data from DOE. Based on these data, the OECM includes separate emission factors for conventional gas production and unconventional production. Emissions factors for GHGs were modified to reflect recent data obtained from DOE's National Energy Technology Laboratory.

The OECM's emissions factors for coal production were updated to reflect recent emissions data from the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. The emissions factors previously used in the OECM for onshore coal production were from the 1990s.

The specific air pollution impacts that the OECM examines and monetizes include the following:

- Adverse human health effects associated with increases in ambient particulate matter with a diameter less than or equal to 2.5 microns ($PM_{2.5}$) and ozone concentrations
- Changes in agricultural productivity caused by changes in ambient ozone concentrations
- Damage to physical structures associated with increases in SO_2.

Because human health effects generally dominate the findings of more detailed air pollution impact analyses (USEPA 2010), excluding emissions-related changes in visibility, forest productivity, and recreational activity from the analysis is unlikely to have a significant effect on the results.

[15] The model monetizes damages associated with emissions in Alaska planning areas by scaling estimates of the monetized damages from APEEP estimates of damages per ton of emissions for the Oregon-Washington Planning Area. The emissions were scaled for both distance from shore and population.

1.5.1.3 OECM Ecological Modeling

The OECM treatment of ecosystem service losses covers some but not all possible losses.[16] An appropriate evaluation of ecological and ecosystem service values involves analyzing the change in ecological and ecosystem service values of the program relative to the No Sale Option. As in the other categories, OECM applies this conceptual approach in its evaluation of ecological and ecosystem service values for the program relative to the No Sale Option by accounting for changes in ecological and ecosystem service values for several categories including ecological losses from oil spills, air quality, commercial fishing, recreational offshore fishing, beach use, property values and aesthetics, and subsistence harvest (BOEM 2015b).

Certain ecosystem service losses are quantified in the OECM. For the Program costs, the OECM uses the probability of oil spills from new oil platforms and pipeline installations to estimate the associated ecosystem service losses. For the No Sale Option, the OECM uses the increased probability/frequency of oil spills due to increased oil imports transported by tankers to estimate the likely associated loss of ecosystem services. In both instances, ecological losses are calculated via HEA within the framework of a natural resource damage assessment where the cost of restoration that equates ecological losses from the oil spill to ecological gains from restoration is used as the monetary measure of ecological damages.

The OECM does not quantify other identifiable ecological and ecosystem service losses. For example, the net benefits analysis does not measure the effects of habitat disturbances from project footprints associated with new oil platforms, pipeline installations, drilling rigs, and any other new infrastructure (beyond incremental air emissions) on the OCS nor passive use losses for marine mammals and other threatened, endangered, and sensitive species adversely affected under the PFP. The OECM also does not count ecosystem service losses (beyond incremental air emissions) that would occur under the No Sale Option. Such losses would arise from incremental habitat disturbances for development of additional onshore oil and gas, renewable energy, and coal resources. Passive use values associated with terrestrial mammals and other threatened, endangered, and sensitive species would also be adversely affected due to incremental development of onshore energy substitutes for offshore oil and gas not developed.

The OECM estimates several types of use values associated with ecological and ecosystem services resulting either from direct or indirect use.[17] While the OECM attempts to quantify the primary categories of ecological and ecosystem service values, it is not designed to represent impacts to unique

[16] Following the definition given by the Millennium Ecosystem Assessment (2003), ecosystem services can be classified into four categories: provisioning services (goods produced from ecosystems such as food, timber, fuel, and water [i.e., commodities]); regulating services (benefits from regulation of ecosystem processes such as flood protection, disease control, and pollination); cultural services (nonmaterial benefits from ecosystems such as recreational, aesthetic, and cultural benefits); and supporting services (services necessary for production of other ecosystem services such as nutrient cycling and soil formation).

[17] Direct use involves human physical involvement with the resources, where direct use can be either consumptive use (e.g., activities that involve consumption or depletion of resources, such as logging or hunting) or non-consumptive (e.g., activities that do not involve resource depletion, such as bird watching). Indirect use involves the services that support the quality of ecosystem services or produced goods used directly by humans (e.g., climate regulation, flood control, animal and fish refugia, pollination, and waste assimilation from wetlands).

resources such as endangered species. Such values would be associated with passive use values (also referred to as non-use values).[18]

Evidence of passive use values can be found in the trade-offs people make to protect or enhance environmental resources that they do not use. Passive use values could be apparent under both the program and the No Sale Option. Overall, an evaluation of passive use values would involve determining the trade-offs made by the public between ecological and species impacts resulting from the incremental oil and gas development under the program versus the ecological and species impacts that would occur onshore from the incremental development of onshore oil, gas, and coal resources under the No Sale Option.

An evaluation of the net change in ecological and ecosystem service values can be accomplished with a variety of economic methods. The most comprehensive approach to evaluating the economic value of ecological and ecosystem service impacts associated with the program versus the No Sale Option would involve administering a nation-wide Stated Preference survey to determine the trade-offs made by the public. However, Stated Preference surveys have their strengths and weaknesses, and require a significant investment in time and resources. Several other factors complicate the ability to implement a SP survey, such as uncertainties about locations of oil and gas development both offshore and onshore, types and extent of habitat disturbances, and types and extent of species impacts that are likely to occur.

In general, the OECM utilizes the benefits-transfer method to estimate economic values associated with ecological and ecosystem services. The magnitude of those values not captured by the OECM is difficult to determine without additional primary research. However, BOEM believes that the OECM provides a representative comparison of the relative size between the program and the No Sale Option for most of the likely ecological and ecosystem service impacts.

1.5.2 Incremental Environmental and Social Costs by Program Area

Returning to the calculation outlined in Figure 1-1: Components of the Net Benefits Analysis in order to obtain the most accurate representation of the differential costs between a program area and the No Sale Option, BOEM must estimate the incremental environmental and social costs for both cases, with the difference in these costs from the program option and the No Sale Option reflecting the net environmental and social costs of each program area. If OCS oil, and, to a lesser extent, natural gas are not produced, imports of foreign oil will increase substantially. Most of this oil would be imported by tanker, entailing risks of oil spills and attendant environmental and social costs. Subtracting the environmental and social costs associated with these increased imports from the same category of costs related to OCS production yields the net environmental and social costs that BOEM attributes to new OCS activities. *MarketSim* quantifies the supply and demand side substitutions for offshore oil and gas production in the absence of lease sales in each of the areas. As shown in Figure 1-3: Calculation of Program Incremental

[18] Passive use values capture individuals' preferences for resources that are not derived directly or indirectly from their use. As such, passive use values can accrue to members of the public who value resources regardless of whether they ever consume or use them. Factors that give rise to passive use values could include the following: desire to preserve the functioning of specific ecosystems; desire to preserve the natural ecosystem to maintain the option for future use; feeling of environmental responsibility or altruism towards plants and animals

Environmental and Social Costs, the OECM then calculates the environmental and social costs from both the program and the No Sale Option for each program area.

Figure 1-3: Calculation of Program Incremental Environmental and Social Costs

Additionally, the incremental environmental and social costs by program area can be expressed in mathematical notation:

$$IESC_i = \sum_{k=1}^{s}\sum_{t=1}^{n}\left[\frac{E_{ikt}}{(1+r)^t}\right] - \sum_{k=1}^{s}\sum_{t=1}^{n}\frac{A_{ikt}}{(1+r)^t}$$

Where:

$IESC_i$ = the incremental environmental and social costs in program area i.
E_{ikt} = the cost to society of the k^{th} environmental externality occurring in program area i in year t.
A_{ikt} = the cost to society of the k^{th} environmental externality occurring in program area i in year t from substitute production and delivery with the No Sale Option.
r = social discount rate

Table 1-7: Incremental Environmental and Social Costs by Program Area, shows the incremental external costs BOEM estimates for each program area. The costs associated with the No Sale Option in Table 1-7 attribute the costs to the program area in which the No Sale Option was selected. For example, No Sale Option impacts listed for the Chukchi Sea would not actually occur in the Chukchi Sea, but rather along the contiguous U.S. coasts and onshore in places of oil, gas, or coal production. The environmental and social costs of the No Sale Option are calculated based on the cost factors in the areas where they are expected to occur, but for presentation in the national net benefits analysis are distributed to program areas based on the expected production from each program area. If benefits and costs are not allocated to the area of production, it would be impossible to link a decision to lease in a specific program area to the full costs and benefits likely to result from that decision. The No Sale Option costs are presented in Chapter 8, Equitable Sharing Consideration, in the PFP in the program area or other region where they are expected to occur.

As shown in Table 1-7 for all program areas, the environmental and social costs of relying on the substitute sources of energy generally exceed those from producing the program area resources (i.e., the external costs under the Program are less than under the No Sale Option).[19] The difference between the costs of the energy market substitutes and the costs of each program area proposal is almost entirely due

[19] The effects estimated by the OECM may be construed as substantial in absolute terms but fairly small in relative terms. For example, the OECM estimates environmental costs for the air emissions associated with a given E&D scenario. Although this is a large figure in monetary terms, these costs are small relative to the environmental costs associated with air pollutant emissions for the entire United States.

to two effects of the No Sale Option. When oil from the new program is not available, increased onshore production of oil, gas, and other energy sources such as coal generates new air emissions. Also, replacement imports of oil cause corresponding increases in air emissions and oil

Table 1-7: Incremental Environmental and Social Costs by Program Area

Program Area	Program Environmental and Social Costs			No Sale Option Environmental and Social Costs			Incremental Environmental and Social Costs		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
	($ billions)								
Beaufort Sea	0.00	0.23	0.37	-	3.85	6.39	0.00	-3.62	-6.02
Chukchi Sea	0.00	0.22	0.31	-	3.59	5.51	0.00	-3.37	-5.20
Cook Inlet	0.01	0.02	0.03	0.19	0.40	0.68	-0.18	-0.38	-0.64
Gulf of Mexico	1.62	4.19	7.20	5.59	10.28	18.31	-3.97	-6.09	-11.12

Notes: All values are discounted at a real discount rate of 3 percent. The low-price case represents a scenario under which inflation-adjusted prices are $40 per barrel for oil and $2.14 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $100 per barrel and $5.34 per mcf. Prices for the high-price case are $160 per barrel and $8.54 per mcf.

spill risks from increased tanker operations along the U.S. coastal areas receiving the oil. Moreover, these added oil imports, along with additional onshore gas production, generate air emissions closer to population centers than occur with OCS oil and gas production. These discharges create a greater exposure influence on human health than do air emissions that often occur many miles offshore. As shown by the results, these extra external effects from replacement supplies are greater than those saved by the modest reduction in overall fossil fuel consumption anticipated under the No Sale Option.

The estimate of environmental effects of the Program omits several conceivable added external costs and benefits, discussed in more detail in Chapter 3, Non-monetized Impacts. First, OECM estimates only those costs that occur within the U.S. boundaries including territorial waters. Thus, there are additional environmental and social costs resulting from foreign oil and gas production for export to the United States and from transportation of oil and gas to U.S. waters or borders, which are excluded from the model. Second, the model does not include a monetization of GHG emissions that would occur under both the Program and No Sale Option scenario. Air emissions, including GHGs associated with increased overseas production and ocean shipments, add to global if not U.S. environmental effects. Third, the model does not consider the consumption of any of the fuel sources as they are assumed to be roughly equivalent under both the Program and No Sale Option. To the extent that additional coal usage replaces natural gas in electricity generation under the No Sale Option, further adverse environmental consequences could occur. However, the slight reduction in consumption under the No Sale Option would slightly reduce the impacts of energy consumption. An expanded discussion of some of these impacts is included in Chapter 3, Non-monetized Impacts.

1.6 DOMESTIC ECONOMIC SURPLUS

The last stage in the net benefits analysis is to add the domestic economic surplus to the difference of the incremental NEV and external costs. The surplus is primarily a result of the societal benefits derived from lower resource prices, and it is a net value because lost domestic producer surplus that would have been generated under the No Sale Option at higher resource prices is deducted. Virtually all of the increase in economic surplus from the program occurs because the added OCS oil and gas production lowers the price consumers pay for imports of oil and gas products compared to the No Sale Option situation. Only a small fraction of the economic surplus is associated directly with the added OCS production. This is the case primarily because the added OCS production supplies only a small fraction of total domestic consumption. The measure of net consumer surplus is calculated using the *MarketSim* software model.

1.6.1 Estimation of Economic Surplus in MarketSim

To assess changes in the welfare of U.S. consumers under a given E&D scenario, *MarketSim* estimates the change in consumer surplus for each of the end-use energy markets included in the model. For a given energy source, changes in consumer surplus occur as a result of changes in both price and quantity relative to baseline conditions. In the OCS case the consumer surplus gains come almost entirely from the price reduction or pecuniary effects of increased OCS oil and gas production. For that reason it is important to measure that change as accurately as possible. In addition to the direct effect of an increase in supply (rightward shift of the supply curve) measured by the own-price elasticity in the oil and the gas markets, *MarketSim* incorporates two other useful relationships in estimating this pecuniary gain.

First, the proposed Five-Year Program would increase the amount of offshore oil and gas production supplied to the economy. The new oil and gas supply will affect other segments of the U.S. energy markets, which create echo effects in the oil and gas market. For example, increased offshore gas production would reduce gas price which leads to a reduction (leftward shift) in coal demand. While reduced coal demand would, in turn, lower the equilibrium coal price, the gas demand curve as specified in the model already includes this feedback effect. Specifically, *MarketSim* incorporates these indirect effects through the use of cross-price elasticity arguments in the primary (e.g., gas in this example) market demand curve, which generally plays out in a smaller equilibrium gas price reduction and gas quantity increase than indicated by the own-price elasticity alone. More detail on how *MarketSim* handles these effects is found in the model's documentation (BOEM 2015c).

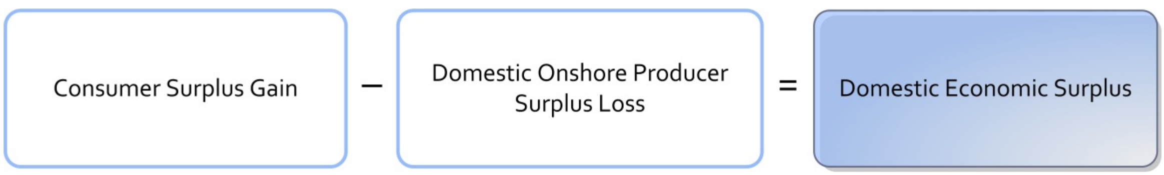
Second, in addition to price elasticity effects, *MarketSim* uses a technique that bases the amount of energy consumed and produced in a given year partially on the quantity consumed and produced in the prior year. That relationship is supported by two aspects of fuel demand. One is that income levels, which drive much of fuel demand, change only gradually from year to year. The other is that fuel is consumed to a large extent in conjunction with durable capital equipment to produce goods or services. Thus, in *MarketSim*, the existing level of income and the size of the capital stock are responsible for influencing a certain level of oil and gas consumption that is independent of resource price effects. Therefore, determination of where equilibrium resource prices settle across multiple markets, and hence estimation of changes in consumer surplus associated with the Five-Year Program, involve careful consideration of market factors other than the traditional demand and supply elasticities.

1.6.2 Netting Out Domestic Producer Surplus

The equilibrium change in the consumer surplus of the oil, gas, coal, and electricity markets overstates the national change in social welfare. Most of this surplus is not a net gain to society as a whole, but only a transfer from producer surplus. Producer surplus occurs when producers receive more than the amount they need to recover their actual and opportunity costs and hence be willing to produce and sell the good. In other words, this surplus is a measure of their economic profit. In the case of the Five-Year Program, the additional OCS production lowers the market price for oil and gas, thus increasing consumer surplus. However, as prices fall, all producers receive a smaller price for every unit of production, thus lowering their producer surplus.

The PFP analysis focuses on gains and losses within the United States. As shown below in Figure 1-4: Domestic Economic Surplus Calculation, only the domestic portion of this lost producer surplus represents an offsetting loss of national welfare. To the extent that new OCS oil and gas would displace imports, all of the consumer surplus benefits which derive from the lower market price and are directly associated with this portion of domestic production represent a net consumer surplus benefit as well. Further, *MarketSim* computes and compiles the net consumer surplus associated with all of the non-U.S. supplied quantities of oil and gas so as to exclude these domestic producer surplus losses from the domestic consumer surplus gains attributed to the program.

Figure 1-4: Domestic Economic Surplus Calculation



The domestic economic surplus measures from production due to the program, aggregated over all the program years and consumption sectors, are shown in Table 1-8: Domestic Economic Surplus, for each of the program areas at the three sets of stipulated resource price levels.

As previously discussed, consumer surplus is driven by resource price changes as a result of adding new OCS leasing. Since oil prices are determined by the world market, OCS leasing does not have a large impact on prices. For example, over the first 50 years of production, the average annual price change in 2017 dollars was $0.52 per barrel for oil and $0.03 per mcf of natural gas. Though these are small changes, applied to all domestic consumption of imports, these result in large economic surplus gains.

Table 1-8: Domestic Economic Surplus

Program Area	Consumer Surplus			Producer Surplus			Domestic Economic Surplus		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
	($ billions)								
Beaufort Sea	0.00	17.40	46.75	0.00	16.12	43.08	0.00	1.27	3.67

Chukchi Sea	0.00	31.44	39.02	0.00	28.98	36.05	0.00	2.47	2.98
Cook Inlet	1.85	5.04	6.41	1.71	4.64	5.88	0.14	0.41	0.53
Gulf of Mexico	48.21	119.75	191.05	43.93	109.56	174.57	4.28	10.19	16.48

Notes: All values are discounted at a real discount rate of 3 percent. The low-price case represents a scenario under which inflation-adjusted prices are $40 per barrel for oil and $2.14 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $100 per barrel and $5.34 per mcf. Prices for the high-price case are $160 per barrel and $8.54 per mcf.

Finally, it may appear at first glance that the inclusion of consumer surplus in the measure of incremental net benefits results in an overestimation of program welfare to U.S. citizens, by inadvertently including that part of consumer surplus which is associated with the export of refined petroleum products. However, that observation would be inaccurate. The measures in this analysis rely heavily on inputs from EIA data outputs and definitions, which are directly employed in *MarketSim*. In the EIA market accounts, and hence in these calculations, the demand for oil and gas for export (most of which is for refined products as opposed to crude oil) is not included on the U.S. market demand side, but instead is on the supply side. In that sense, market demand is purely domestic demand for oil and gas. Thus, as a result of the omission of exported oil refined products from domestic demand in both the EIA output tables and hence in the model calculations, the net benefits analysis properly reflects the consumer surplus only for U.S. citizens from production of OCS crude oil.

1.7 INCREMENTAL NET BENEFITS SUMMARY

Table 1-9: Incremental Net Benefits shows the total incremental net benefits associated with the program area resources projected to be leased, discovered, and produced in the PFP. The total incremental net benefits are the incremental NEV less the environmental and social costs plus the domestic economic surplus. The net benefits for the PFP Options are calculated as incremental because they are the costs and benefits of OCS leasing less the costs and benefits in the No Sale Option. For example, the incremental net benefits of $65.27 billion in the mid-price case for the GOM represent the value of the program area above the No Sale Option.

Table 1-9: Incremental Net Benefits

Program Area	Incremental NEV			Incremental Environmental & Social Costs			Domestic Economic Surplus			Incremental Net Benefits		
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
	($ billions)											
Beaufort Sea	-2.46	17.61	79.28	0.00	-3.62	-6.02	0.00	1.27	3.67	-2.46	22.50	88.96
Chukchi Sea	-0.42	40.32	130.78	0.00	-3.37	-5.20	0.00	2.47	2.98	-0.42	46.16	138.95
Cook Inlet	0.10	4.69	13.03	-0.18	-0.38	-0.64	0.14	0.41	0.53	0.42	5.48	14.20
Gulf of Mexico	2.40	48.99	169.98	-3.97	-6.09	-11.12	4.28	10.19	16.48	10.65	65.27	197.58

Notes: All values are discounted at a real discount rate of 3 percent. The low-price case represents a scenario under which inflation-adjusted prices are $40 per barrel for oil and $2.14 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $100 per barrel and $5.34 per mcf. Prices for the high-price case are $160 per barrel and $8.54 per mcf.

Chapter 2 Catastrophic Oil Spills

2.1 Introduction

In the aftermath of the *Deepwater Horizon* event in April 2010, BOEM considers the potential impact of low-probability/high-consequence oil spills more explicitly in its Program assessments of future OCS exploration, development, and production activities. A decision as to whether or not to proceed with proposed lease sales necessarily carries with it the risk, however slight, of a catastrophic oil spill, regardless of the decision. This document primarily addresses environmental and social resources and activities that could be affected by a catastrophic oil spill resulting from OCS oil and gas activities anticipated from leases issued during the Program. However, a decision not to lease incurs a risk that a catastrophic oil spill could result from tankers importing oil in lieu of OCS production. If the No Sale Option is selected for one or more program areas, there may also be catastrophic risks from other energy substitutes, including coal and nuclear energy.

The potential catastrophic oil spill costs to society in quantitative or monetary terms are highly dependent upon the circumstances of the event and its aftermath. The wide and unpredictable nature of factors that alone or in combination can influence a catastrophic oil spill's impact include, but are not limited to, human response, spill location, reservoir size and complexity, response and containment capabilities, meteorological and metocean conditions, and the type and volume of oil spilled. As a result, quantification of costs is far less certain than in other components of the net benefits analysis. For that reason, BOEM presents estimates of the social and environmental costs of possible catastrophic spill sizes separately from the results of the net benefits analysis. The assumptions reflect a scenario where the social and environmental impacts are likely overestimates of the impacts that might occur.

A catastrophic spill is not expected during the Five-Year Program. A catastrophic event of this nature is considered well outside the normal probability range despite the inherent risks of oil production-related activities. Even if not expected, the impact from this type of event is considered in this analysis. Regulatory changes and improved industry prevention and safety practices since *Deepwater Horizon* make the occurrence of an event similar in magnitude significantly less likely. Recently implemented safeguards enhance overall drilling safety. These safeguards include enhanced industry engineering, technical, and operational standards and best practices, and stricter BOEM/Bureau of Safety and Environmental Enforcement (BSEE) regulatory requirements. Final and proposed regulations include new standards for well-design, casing, cementing and well control requirements. Other regulations enhance workplace safety by requiring companies to develop and maintain a Safety and Environmental Management System. Together, these regulatory reforms, explained in further detail below, reduce the likelihood of a low-probability/high-consequence event but do not entirely eliminate the risk.

2.2 Recent Risk Reduction Efforts

Industry and the Government have achieved extensive progress improving offshore energy exploration safety and well-bore integrity post-*Deepwater Horizon*. Both industry and Government have taken significant steps to reduce the likelihood of well control incidents and mitigate the prospect of a well control event developing into a catastrophic spill. These efforts address a spectrum of factors throughout the OCS exploration and development process.

2.2.1 Industry Efforts

The BOEM/BSEE regulatory approach to drilling safety depends heavily on the incorporation of industry standards by reference and sharing of best practices among oil and gas operators and contractors. Industry typically responds more quickly than the Government when referenced standards become outdated or technological developments yield improved equipment or best practices.

The most common standards referenced in BOEM/BSEE regulations are American Petroleum Institute (API) standards and specifications that are the result of collaboration efforts among industry, Government, and academia experts. Issuance and updates to standards reflect the latest knowledge and experience of subject matter experts, including incorporation of lessons learned from actual operations.

Operators utilize recognized exploration and development engineering solutions and best practices as referenced in BSEE regulations or industry standards. This approach reduces oil spill and other accident risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities.

One leading industry effort is the Center for Offshore Safety (COS). The COS is an industry-sponsored organization focused exclusively on offshore safety. The COS serves the U.S. offshore oil and gas industry with the purpose of adopting standards of excellence to ensure continuous improvement in safety and offshore operational integrity.

The major offshore drilling contractors are spearheading other industry efforts. One effort, known as the "Group of 7," has developed a database of blowout preventer (BOP) component failures or repairs. By tracking, reporting, and analyzing failures of BOP equipment over time, this database supports the development of design, functionality, and maintenance requirements that enhance BOP component reliability. The International Association of Drilling Contractors established the Well Control Institute (WCI) that brings together representatives and stakeholders from the drilling industry to develop the comprehensive solutions necessary to significantly improve human performance in well control worldwide. The WCI provides a forum for operators, contractors, equipment manufacturers, regulators, and service providers to collaborate on well control initiatives.

The oil and gas industry assembled four Joint Industry Task Forces (JITFs) of industry experts to identify best practices in offshore drilling operations and oil spill (API 2015). Outcomes and recommendations were issued in 2012 and include:

Procedures JITF: This task force developed guidelines for the Well Construction Interface Document, which will address drilling contractor's Health, Safety, and Environmental plans and the operator's Safety and Environmental Management System (SEMS) and safety and risk management considerations on a well-by-well basis.

Equipment JITF: This task force reviewed current BOP equipment designs, testing protocols, and documentation. Their recommendations were designed to close any gaps or capture improvements in these areas. The JITF recommendations are incorporated into API STD 53 *Blowout Prevention Equipment Systems for Drilling Wells*.

Subsea Well Control and Containment JITF: This task force developed recommendations for enhancing capabilities to capture and contain hydrocarbons quickly after a well blowout (API 2012). This capability was achieved through the establishment of two collaborative containment companies – the Marine Well Containment Company (MWCC) and Helix Well Containment Group's Helix Fast Response System. These two companies house the equipment and technology needed to quickly and effectively respond to loss of well control events.

Oil Spill Preparedness and Response JITF: This task force identified potential opportunities for improving oil spill response (API 2011). The recommendations were subsequently addressed by the API Oil Spill Preparedness and Response Subcommittee (OSPRS). The OSPRS developed an industry-funded, multi-year work program with projects in seven different work areas including: planning, dispersants, shoreline protection and cleanup, oil sensing and tracking, *in situ* burning, mechanical recovery, and alternative technologies.

The offshore oil and gas industry has a vested interest in ensuring protective and safe operations. Industry efforts post-*Deepwater Horizon* have significantly increased safety margins and protection of OCS resources.

2.2.2 Government Efforts

In addition to the routine updates of performance-based and prescriptive regulations, compliance inspections and other regulatory tools, BOEM and BSEE participate in the Ocean Energy Safety Institute (OESI). The OESI provides a forum for dialogue, shared learning, and cooperative research among academia, Government, industry, and other non-governmental organizations, in offshore energy-related technologies and activities that ensure safe and environmentally responsible offshore operations. The OESI coordinates efforts to identify scientific and technological gaps and to recommend improvement of drilling and production equipment, practices, and regulation. The OESI also supports the continuous education and training of BSEE and BOEM employees to ensure they maintain the same level of technological expertise as the engineers, scientists, and technical experts in the oil and gas industry.

BSEE has initiated a series of reforms aimed at strengthening existing regulations to prevent oil spills. These include the Drilling Safety Rule, Workplace Safety Rule, Blowout Preventer Systems and Well Control Rule and the BOEM/BSEE Arctic Exploration Rule. Additionally, BSEE has increased its inspection and compliance efforts (BSEE 2011a). These efforts include:

- The Drilling Safety Rule implemented more rigorous standards for well design, casing and cementing practices, and blowout preventers.
- The Workplace Safety Rule requires companies to implement and maintain SEMS programs. SEMS is a performance-based system for offshore drilling and production operations focusing on hazard analysis and mitigating risks.
- The Blowout Preventer Systems and Well Control Rule implemented multiple recommendations from various investigations and reports of the *Deepwater Horizon* tragedy.

- The Arctic Exploration Rule provides regulations to ensure Arctic OCS exploratory drilling operations are conducted in a safe and responsible manner that takes into account the unique conditions of Arctic OCS drilling.
- Since 2010, the inspector/investigator workforce has increased more than 40 percent and BSEE has begun to develop and implement a new inspection strategy that focuses on risk and the use of advanced inspection technologies (BSEE 2016). BSEE inspectors now witness far more activity on drilling rigs than before the *Deepwater Horizon* event, including critical tests of blowout preventers. Further reducing the likelihood of a well control incident developing into a catastrophic oil spill, BSEE now requires operators to have access to a well containment system before approving a drilling permit.

In addition to these regulatory and procedural reforms, Government agencies have expanded and refocused a number of research and development efforts aimed at improving technologies for spill prevention, containment and response, many that pre-date the *Deepwater Horizon* event. These efforts include:

BSEE's Technology Assessment Program: This program has funded more than 700 research projects since the 1970s related to oil, gas, and renewable energy development and is increasingly focused on safety issues associated with operations in the Arctic environment (BSEE Undated a).

BSEE's Oil Spill Response Research Program: As part of the post-*Deepwater Horizon* reorganization, the Oil Spill Preparedness Division (OSPD) was established to consolidate all efforts undertaken by BSEE to ensure that industry is prepared to respond to an offshore oil spill. The Oil Spill Response Research Program is housed in OSPD to allow direct alignment with BSEE's decision makers in oil spill preparedness. Since its inception, the research program has funded over 70 new research projects on dispersants, mechanical recovery, command and control, remote sensing, and other areas to improve offshore oil spill response. BSEE also operates Ohmsett, the National Oil Spill Response Research and Renewable Energy Test Facility in Leonardo, New Jersey. This is the only facility where full-scale oil spill response equipment testing, research, and training can be conducted in a marine environment with oil under controlled environmental conditions (waves and oil types) (BSEE Undated b).

Department of Energy's Ultra-Deepwater Research Program (DOE Undated)[20]: This is a joint Government-industry research and development (R&D) program run by DOE and originally focused generally on R&D related to deepwater oil and gas production. Since the *Deepwater Horizon* event, the program has shifted its emphasis to assessing and mitigating risk associated with drilling operations. The Ultra-Deepwater Advisory Committee, which advises DOE on the Ultra-Deepwater Program, has also recommended research on human factors related to drilling safety.

Interagency Coordinating Committee on Oil Pollution Research (ICCOPR): The ICCOPR is a 15-member interagency committee established under the Oil Pollution Act of 1990. The purpose of the Interagency Committee is two-fold: (1) to prepare a comprehensive, coordinated Federal oil pollution research and development plan; and (2) to promote cooperation with industry, universities, research institutions, state governments, and other nations through information sharing, coordinated planning, and joint funding of projects. In 2015, ICCOPR updated its Oil Pollution Research and Technology Plan

[20] The full title of the program is the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Program.

(ICCOPR 2015) to set priorities for federal oil pollution in the areas of response, prevention, preparedness, and injury assessment and recovery. This plan identifies 150 priority research needs in 25 standing research areas.

Ocean Energy Safety Advisory Committee (OESC) (BSEE Undated c): The OESC was a public Federal advisory body of the nation's leading scientific, engineering, and technical experts. The group consisted of 15 members from Federal agencies, the offshore oil and gas industry, academia, and various research organizations. The Committee provided critical policy advice to Secretary of the Interior through the BSEE Director on improving all aspects of ocean energy safety.

While catastrophic spill risks can never be completely eliminated, significant government and industry efforts continue to reduce the likelihood of an OCS catastrophic oil spill and reduce the duration of a spill should one occur. Human error is usually at least a contributing factor in low-probability/high-consequence accidents, and the greater focus on human factors including the SEMS hazard analysis and the Marine Well Containment Company and Helix Well Containment Group and Helix rapid response well capping, and cap and flow systems should greatly reduce the likelihood that a loss of well control event will evolve into a prolonged, catastrophic oil spill.

2.3 Quantifying the Possible Effects of a Catastrophic Spill

Section 2.3, Quantifying the Possible Effects of a Catastrophic Spill, presents BOEM's calculations of the potential costs of a hypothetical oil spill. This section also supplements the Section 18 net benefits analysis (Section 5.3 in the PFP decision document), where the costs of expected smaller-sized oil spills are considered.

2.3.1 What is a Catastrophic Spill?

For purposes of this analysis, a catastrophic OCS event is defined as any high-volume, long-duration oil spill from a well blow-out, regardless of its cause (e.g., a hurricane, human error, terrorism). The National Oil and Hazardous Substances Pollution Contingency Plan further defines such a catastrophic event as a "spill of national significance," or one that "due to its severity, size, location, actual or potential impact on the public health and welfare or the environment, or the necessary response effort, is so complex that it requires extraordinary coordination of Federal, state, local, and responsible party resources to contain and clean up the discharge" (40 CFR 300, Appendix E) (BOEM 2014a).

This assessment of the potential costs of a catastrophic oil spill of national significance does not mean that a catastrophic event can be pinned down to an expected cost measure comparable to other values estimated for OCS activity. With few OCS catastrophic oil spill data points, statistically predicting a catastrophic blowout event that produces an oil spill consistent with the programmatic analysis for the Final Programmatic EIS and data from both U.S. OCS and international offshore drilling history is beset with uncertainties. An effort to calculate the frequency of a catastrophic oil spill is described in the Section 2.4, Detailed Frequency Calculations.

While the risk is not zero, a catastrophic spill is not anticipated from this Five-Year Program or from energy substitutes the market would supply if the No Sale Option were selected in any or all program areas. Consistent with Executive Order 13547, *Stewardship of the Ocean, Our Coasts, and the Great*

Lakes, BOEM uses "(2.iv) the best available science and knowledge to inform decisions affecting the ocean, our coasts, and the Great Lakes . . ." Using this best available information, the analysis in this chapter attempts to estimate the costs of a hypothetical catastrophic spill in each of the five program areas.

2.3.2 Catastrophic Oil Spill Sizes

For consideration of potential environmental and social costs that might result from catastrophic events, BOEM adopts the hypothetical catastrophic oil spill size specifications, by program area, used for the Programmatic EIS (BOEM 2016b). The catastrophic spill analysis estimates the social and environmental costs for a range of hypothetical spill sizes: 150,000; 500,000; 1,000,000; 2,000,000; 5,000,000; and 10,000,000 barrels. This range of spill sizes was developed by applying extreme value statistics to historical OCS spill data (Ji et al. 2014). Although the event of a catastrophic oil spill is unlikely, BOEM utilizes these reference sizes in considering the costs of a range of possible catastrophic spills. Table 2-1: Estimated Loss of Well Control Frequency per Well for Given Spill Size Volumes provides the range of spill sizes considered and shows how unlikely each event would be to occur.

Table 2-1: Estimated Loss of Well Control Frequency per Well for Given Spill Size Volumes

Hypothetical Spill Size (barrels)	Approximate Frequency per Well $f = 0.00099Q^{-0.24078}$	Approximate Frequency (1 in X wells)	Percent Spills Expected to be Less than or Equal to Given Spill Size
150,000	0.00005641	17,729	97.4%
500,000	0.00004221	23,691	98.8%
1,000,000	0.00003572	27,994	99.3%
2,000,000	0.00003023	33,078	99.6%
5,000,000	0.00002425	41,243	99.8%
10,000,000	0.00002052	48,734	99.87%

Notes: Q refers to the hypothetical spill size. The parameters used in the Approximate Frequency per Well equation are rounded for display purposes, but the longer form numbers were used in the original calculation. As a result, the estimates in this column may appear slightly different. The approximate frequency estimate is based on an exceedance value. The frequency of one in X wells is the frequency of having a loss of well control incident and an oil spill of a particular catastrophic volume or greater..

2.3.3 Statistical Frequency of a Catastrophic Oil Spill

In order to calculate the *risked* social and environmental costs from a catastrophic spill that could, but is not expected to occur in this program, BOEM developed a frequency estimate based on historical analysis of the likelihood of a well blowout that would result in an oil spill of a catastrophic size. The historical statistical frequency exceedance value used in this analysis is likely significantly higher than the actual future frequency due to the proactive actions of the government and industry to reduce the chance of another blowout and catastrophic oil spill. However, absent new data regarding the frequency of catastrophic oil spills under the new regulatory regime, BOEM uses historical exceedance frequency values derived from U.S. OCS drilling and blowout data from 1964–2014.[21] The larger the size of a spill, the smaller is the frequency of a loss of well control event producing a spill of that size or greater. Even using all available historical data in the dataset, there are still issues with a small sample size based on a limited number of blowouts and an even smaller number of blowouts leading to oil spills.

From 1964–2014, more than 42,000 wells were drilled with only 307 loss of well control instances (BSEE 2015).[22] Of the loss of well control instances, only 65 resulted in an oil spill. These data were used to approximate the loss of well control frequency shown in Table 2-1: Estimated Loss of Well Control Frequency per Well for Given Spill Size Volumes. Almost all oil spills resulting from loss of well control instances were very small. The median spill size of these 65 events (including *Deepwater Horizon*) is only two barrels. More details on how these frequencies were developed are provided below in Section 2.4, Detailed Frequency Calculations.

To calculate the estimated loss of well control frequency by program area, the frequencies in Table 2-1: Estimated Loss of Well Control Frequency per Well for Given Spill Size Volumes are multiplied by the total number of wells projected for the E&D mid-price case scenario for each program area.[23] This price case serves as a useful mid-point between the two other price cases analyzed in this document. The frequencies presented in Table 2-2: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Price Case represent the number of spills of a particular size or greater which can be expected over the life of the Program in each program area.

Table 2-2: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Price Case

Hypothetical Spill Size (barrels)	**Region**		
	Arctic	Cook Inlet	Gulf of Mexico
150,000	0.0974	0.0042	0.1868
500,000	0.0729	0.0032	0.1398
1,000,000	0.0617	0.0027	0.1183
2,000,000	0.0522	0.0023	0.1001
5,000,000	0.0419	0.0018	0.0803
10,000,000	0.0354	0.0015	0.0680

No single type of accident automatically results in a multi-million-barrel release of oil. Because each safeguard and response mechanism has its own probability of success, the cumulative probability of failure is lower for larger volumes (just as the probability of rolling a die and getting the same number 10 times in a row is much less likely than getting the same number only the first four times the die is rolled).

[21] Despite changes in technology and the move into deeper water, rate of loss of well control incidents has remained fairly constant over this period, making it appropriate for our analysis. One likely reason for this is that as drilling challenges increase, companies develop corresponding technology to address well control and other issues.
[22] As defined in BSEE regulations for incident report, Loss of Well Control means: an uncontrolled flow of formation or other fluids, whether a result of an underground or surface blowout; a flow through a diverter; or an uncontrolled flow resulting from a failure of surface equipment or procedures.
[23] The total number of wells projected in the E&D mid-price case scenario is as follows: 1,727 wells for the Arctic, 75 wells for Cook Inlet, and 3,312 wells for the GOM.

2.3.4 Environmental and Social Costs of a Catastrophic Oil Spill

As described above, a catastrophic oil spill event is assumed to be the release of a large volume of oil over a long period of time from a well control incident. However, the spill size volume is only one factor that influences the nature and severity of the event's impacts. Other factors, alone or in combination, can influence a catastrophic oil spill's impact, including but not limited to the duration of the spill, human response, spill location, reservoir size and complexity, response and containment capabilities, meteorological and metoean conditions, and the type of oil spilled. Rather than account for each of these variables and adjust the impacts and costs accordingly, BOEM uses a benefit transfer approach based on spill size, with major cost categories serving as an approximation of the largest foreseeable environmental and social costs of a catastrophic spill in each program area. The benefit transfer approach is a method that applies economic values obtained from previous studies or historical data to a new location and/or context where primary data have not been collected.

The economic cost of a catastrophic oil spill for this analysis is the value of the resources used or destroyed as a result of the spill, as well as the flow abatement and response (e.g., cleanup) expenses. The economic cost of a spill may differ from the amount of compensation paid by responsible parties to those affected. Compensable damage is dependent upon particular legal statutes in place in the affected countries and may or may not include all aspects of the economic cost of a spill.

To calculate the impacts associated with a catastrophic oil spill, BOEM catalogued several environmental and social cost categories. The seven major categories considered in this analysis are: response or clean-up costs, ecological damages, recreational use, commercial fishing, subsistence, fatal and nonfatal injury, and the value of lost hydrocarbons. With the estimates for these cost categories, BOEM used the hypothetical range of spill sizes from Section 1.3.2, Market Simulation Model, to calculate the cost of a spill.

The environmental and social costs by program area for a catastrophic event, calculated on a per barrel or fixed, per event basis, are summarized below in Table 2-3: Per Barrel Variable Environmental and Social Costs ($/bbl)and Table 2-4: Fixed (Per Event) Environmental and Social Costs ($ millions). For a spill, the fixed costs are incurred regardless of the spill volume. More detailed information on the data and methods used to calculate these costs is provided in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015b). For additional analysis of the environmental and socioeconomic impacts related to a catastrophic spill, see Chapter 4 of the Final Programmatic EIS (BOEM 2016b).

Table 2-3: Per Barrel Variable Environmental and Social Costs ($/bbl)

Cost Category ($/bbl)	Arctic	Cook Inlet	Gulf of Mexico
Ecological Damages	2,500 – 9,700	1,080 - 4,200	580 - 2,200
Response Costs	1,500 – 16,000	16,000	5,100
Value of Lost Hydrocarbons	100	100	100
Recreation **	-	23	188
Commercial Fishing	-	*	41
Subsistence	*	193	-

Table 2-4: Fixed (Per Event) Environmental and Social Costs ($ millions)

Cost Category ($ millions)	Arctic	Cook Inlet	Gulf of Mexico
Fatal & Nonfatal Injuries	76.4	76.4	76.4
Subsistence	209	*	-
Recreation/Wildlife Viewing	-	94.6	-
Commercial Fishing	-	43.5	-

2.3.5 Estimated Program Area Results

BOEM presents two separate ways to consider the costs of a catastrophic spill: conditional costs and risked costs. Conditional costs represent an estimate of the costs of a spill should one occur. Risked costs consider the probability that a spill would occur and are discounted by this probability. Due to low and high cost estimates for the ecological damages and response cost categories, ranges are presented for both conditional and risked costs. For more information on the uncertainty underlying the range of the costs for ecological damages and response costs, refer to *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015b).

2.3.5.1 Conditional Catastrophic Spill Costs

The conditional costs of a catastrophic oil spill are simply the estimated costs should the spill occur. Table 2-5: Conditional Catastrophic Spill Costs shows the estimated spill costs of a catastrophic spill for each program area. While a catastrophic oil spill is not expected in this Program, if a spill were to occur, Table 2-5 provides an estimate of what these costs might be. These conditional costs vary within a program area based solely on the size of the spill, but in practice they can vary as well by specific location of the spill, season of the year, wind conditions, etc. The estimates were made using conservative assumptions for these factors.

Table 2-5: Conditional Catastrophic Spill Costs

Spill Size (barrels)	Arctic	Cook Inlet	Gulf of Mexico
	$ Billions		
150,000	1.4 - 4.2	2.8 - 3.3	1 - 1.2
500,000	4.1 - 13.2	8.9 - 10.5	3.1 - 3.9
1,000,000	8 - 26.1	17.6 - 20.7	6.1 - 7.7
2,000,000	15.7 - 51.9	35 - 41.2	12.1 - 15.3
5,000,000	38.8 - 129.3	87.2 - 102.8	30.1 - 38.2
10,000,000	77.3 - 258.3	174.2 - 205.4	60.2 - 76.4

While Table 2-5 shows the conditional costs of a catastrophic oil spill, these values are not comparable to the results in the net benefits analysis. The net benefits analysis shows the discounted value of benefits expected from each program area. To be consistent with the net benefits analysis, the conditional spill costs should be discounted over the life of the program. However, even discounted, conditional spill costs are not comparable since they do not represent a risked value, but instead represent the cost of a spill should one occur.

To discount the conditional costs, BOEM distributed the conditional cost of a spill over time based on the number of wells drilled in each program area in each year to approximate the concentration of the risk of a spill.[24] The results, shown in Table 2-6: Present Values of Conditional Catastrophic Spill Costs, are then discounted back to 2017 at 3 percent and summed. The conditional costs are highest in the Arctic and Cook Inlet, where there are large per event costs (i.e., subsistence losses) and damage and response costs are higher than other program areas.

Table 2-6: Present Values of Conditional Catastrophic Spill Costs

Region	Arctic	Cook Inlet	Gulf of Mexico
Spill Size (barrels)	$ Billions		
150,000	0.7 - 2.1	1.9 - 2.2	0.6 - 0.8
500,000	2.1 - 6.6	6 - 7	2 - 2.5
1,000,000	4 - 13.1	11.8 - 13.9	3.9 - 5
2,000,000	7.8 - 26	23.6 - 27.8	7.8 - 9.9
5,000,000	19.4 - 64.7	58.7 - 69.2	19.5 - 24.7
10,000,000	38.7 - 129.2	117.2 - 138.2	38.9 - 49.4

Note: All values are discounted to 2017 at a real discount rate of 3 percent.

2.3.5.2 Risked Catastrophic Spill Costs

While the conditional costs show valuable information on the impacts if a catastrophic spill did happen, a catastrophic spill in any of the program areas from this Five-Year Program is highly unlikely. To consider the risked costs of a spill, BOEM multiplies the conditional costs of a catastrophic spill by the statistical frequencies per program area from Table 2-2: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Price Case. The results, displayed in Table 2-7: Estimated Risked Catastrophic Spill Costs, are essentially the statistical expected values of a catastrophic oil spill. These are the sum of the annual, risked costs discounted back to 2017 at three percent following the same methodology used for calculating the present values of conditional spill costs.

Table 2-7: Estimated Risked Catastrophic Spill Costs

Region	Arctic	Cook Inlet	Gulf of Mexico
Spill Size (barrels)	$ Billions		
150,000	0.07 - 0.2	0.01 - 0.01	0.12 - 0.15
500,000	0.15 - 0.48	0.02 - 0.02	0.28 - 0.35
1,000,000	0.25 - 0.81	0.03 - 0.04	0.47 - 0.59
2,000,000	0.41 - 1.36	0.05 - 0.06	0.78 - 0.99
5,000,000	0.81 - 2.71	0.11 - 0.13	1.57 - 1.99
10,000,000	1.37 - 4.58	0.18 - 0.21	2.65 - 3.36

Note: All values are discounted to 2017 at a real discount rate of 3 percent.

[24] Using the timing of all wells drilled in the mid-price E&D scenario.

When compared to the conditional costs, the risked costs of a catastrophic oil spill are significantly less given the unlikely nature of a catastrophic oil spill. Although these costs are not inconsequential, they represent a fraction of the incremental net benefits expected in each program area.

Regardless of whether considering conditional or risked costs, the benefits attributable to the Program are often higher than the spill costs. For the costs to surpass the expected benefits, spill events would generally have to occur more frequently (i.e., loss of well control events would occur at an accelerated rate not observed in the 1964–2014 data) and/or at a higher cost. Cost data from existing spills, including the *Exxon Valdez* and *Deepwater Horizon* settlements, do not suggest that these cost levels would likely occur. Further industry improvements to both prevent catastrophic oil spills and minimize their duration further reduce the extremely small likelihood of a catastrophic oil spill.

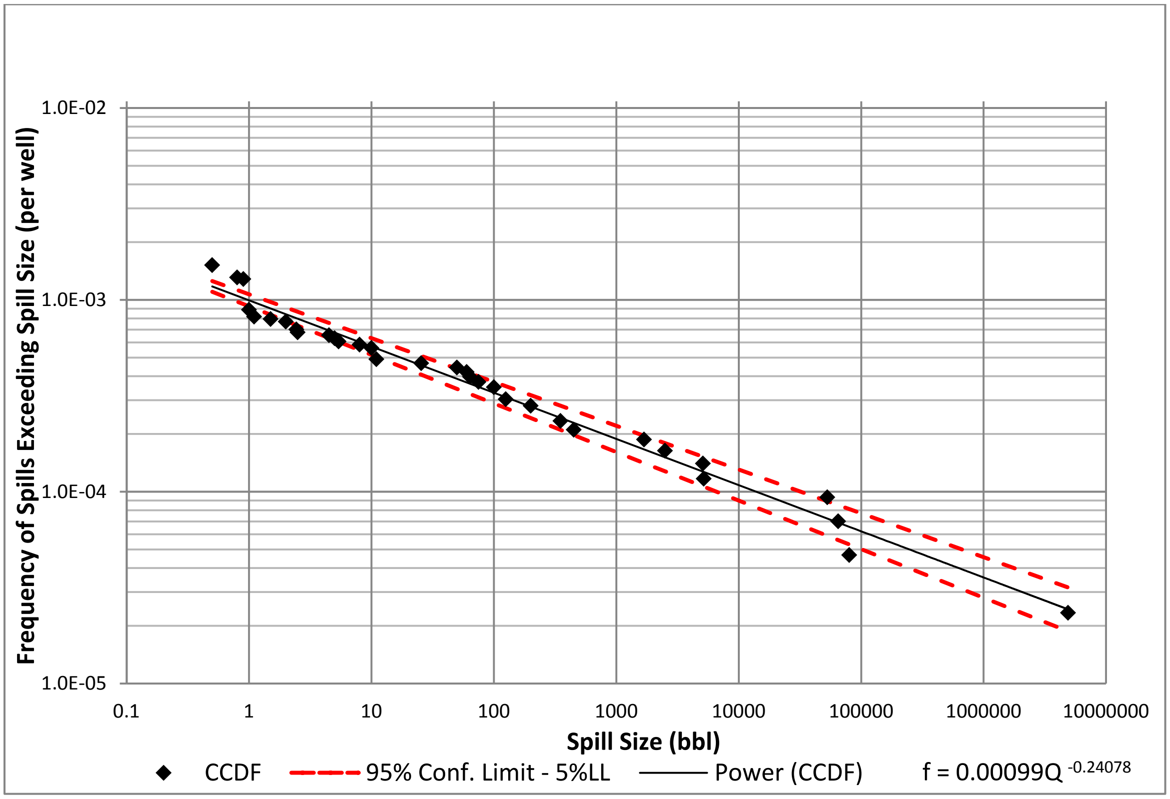
2.4 DETAILED FREQUENCY CALCULATIONS

To make estimates regarding the risked cost of a catastrophic oil spill, an estimate of probability of an event occurring was necessary. Probabilities or approximate estimates of loss of well control frequency, shown in Table 2-2: Frequency of Hypothetical Spill Size or Greater by Program Area in Mid-Price Case, were calculated using regression analysis on loss of well control data. The result of the analysis, displayed in Figure 2-1: Frequency Curve for Spills Resulting from Loss of Well Control on the OCS through 2014, shows the frequency of loss of well control experienced per well drilled with an oil spill exceeding a specified size. The equation from this calculation allowed BOEM to use the spill sizes defined in Section 2.3.2, Catastrophic Oil Spill Sizes, to determine the frequency of loss of well over a range of catastrophic discharge events.

The BSEE database on loss of well control (LWC) used for this analysis includes incidents from 1956 to the present day. Most records in the BSEE Listing and Status of Accident Investigations database can be viewed at http://www.data.bsee.gov/homepg/data_center/other/tables/safetylist.asp. The BSEE database also contains a few additional observations besides those available online. As can be expected, the quality of information improves as a function of time. Only the period 1964–2014 is considered herein because of adequate quality of the information. BOEM undertook a substantial effort to inspect the data for quality, when possible identifying and confirming for each incident the relevant API well number, bottom OCS lease number, platform and/or rig, etc. This allowed BOEM to check the timing of a particular LWC incident relative to well operations documented in shared BSEE/BOEM information management systems.

The sample size of OCS LWC incidents is small, even when including all OCS Regions. No LWC incidents have occurred or have been reported in the Alaska or Atlantic OCS Regions. To obtain a sufficiently large sample size to estimate both historical frequency of LWC and the relative frequency of different sized oil spills (resulting from LWC), 307 incidents between 1964 and 2014 are considered. Most historical LWC incidents resulted in the surface release or diversion of natural gas; in fact, the database only includes 65 instances of crude or condensate surface releases since 1964. Moreover, the typical crude or condensate spill size is relatively small; the median spill size, including the *Deepwater Horizon* event, between 1964 and 2014 was two barrels. The mean spill size for the same time period was 78,682 barrels, though the mean spill size drops to approximately 3,350 barrels when the *Deepwater Horizon* event is excluded.

Figure 2-1: Frequency Curve for Spills Resulting from Loss of Well Control on the OCS through 2014



The power law fitting ($f = \alpha Q^{\beta}$) was used for the LWC data and follows the methodology presented in DNV (2010). In this equation, f corresponds to the frequency of crude/condensate spills per well exceeding spill size Q (bbl). Alpha (α) describes the relative frequency of spill occurrence, whereas beta (β) defines the power relation between spill size and frequency. The complementary cumulative density function (CCDF), or sample complementary cumulative frequency distribution, shows the number of spill events per exposure that are greater than or equal to a given spill size.

2.5 Catastrophic Risks of the No Sale Options

Any analysis of the risks of OCS exploration and development must also be balanced with the increased risk of other catastrophic events in the absence of the Five-Year Program. BOEM's analysis of energy markets under of any of the No Sale Options indicates that there would only be a small decrease in overall energy demand as a result of the higher oil and gas prices in the absence of new OCS oil and gas development. The vast majority of forgone OCS production would be made-up by non-OCS oil and gas, or from other energy market substitutes such as coal, nuclear, or renewable energy sources. Most of these energy substitutes also entail some degree of catastrophic risk. Although it is difficult to quantify the extent catastrophic risks for producing energy substitutes would increase in the absence of OCS production, the discussion below highlights some of the potential risks of these energy substitutes.

The most direct result of selecting the No Sale Option would be increased production of domestic onshore oil and gas and increased foreign oil imports. While onshore oil production does not incur the same types of risks of catastrophic well blowouts as offshore oil production, the blowouts that could occur can still impose intense local damage. Once the oil or gas has been extracted, there is additional risk in transporting the resources to market. If trains and other equipment are not secured or deployed properly, trains may derail and potentially spill combustible crude oil (Business Insider 2015). The Federal Railroad Administration continues to address track problems and issues with tank car design and railroad operation, but transporting crude oil inherently poses some degree of risk.

Further, substituting domestic oil with foreign oil effectively shifts some of the oil spill risk—particularly production-related risk—from the United States to other countries. While many countries have extremely rigorous safety standards and regulatory regimes for oil and gas operations, other countries have significant gaps in addressing spill risk. In fact, devastating offshore oil spills have occurred worldwide. Notable examples include the 1979 IXTOC I well blowout that spilled a reported approximate 30,000 barrels of oil per day into the GOM for 9 months (NOAA 1979); and the 1988 Piper Alpha platform fire in the North Sea that killed 167 personnel (Paté-Cornell 1993). Similarly, increased imports of oil via tanker increase the risk of major spills nearer sensitive areas and population centers as tankers can carry several million barrels of oil at a time. Multiple hull tanker designs have dramatically reduced the risk of a tanker losing its entire cargo, but likely worst case discharge scenarios for tanker accidents are still in the range of several hundred thousand barrels of oil (Etkin 2003), and tankers tend to have more accidents close to shore, where the impacts are generally more severe.

Other types of catastrophic impacts can occur even with energy substitutes to OCS oil and gas. Severe impacts may happen throughout the energy supply chain leading from the extraction of raw materials to the production of fuels to the end-use of energy for heating, transportation, or power production. In some cases, as in offshore oil and gas extraction, catastrophic accidents can occur upstream in the energy chain. In other cases, there is potential for catastrophic accidents in downstream activities such as power production. Examples include the following:

- Nuclear Power: The high-profile disasters at Chernobyl and Fukushima Daiichi highlight the risks of worst-case nuclear power plant accidents. Nuclear reactors also produce radioactive waste, creating the potential for environmental contamination.
- Coal: Upstream mining involves the risk of mine accidents and severe environmental damage from acid runoff into groundwater. Downstream power generating activities produce fly ash, which must be contained and disposed of to avoid environmental contamination. In 2008, a fly ash storage pond breach in the Tennessee Valley Authority’s (TVA’s) Kingston, Tennessee, power plant resulted in the release of 5.4 million cubic yards of fly ash. Cleanup costs are estimated at $1.2 billion (Bloomberg Business 2011). On February 2014, up to 39,000 tons of coal ash spilled from Duke Energy’s Dan River Steam Station into the Dan River in Eden, North Carolina. The USEPA entered into a $3 million cleanup agreement with Duke Energy Carolinas, LLC to address the damages (USEPA 2014).

It is difficult to quantitatively compare the risk and impact of one energy source over another, let alone to calculate the incremental increases in risk from energy substitutions. However, these examples reinforce that energy production is never risk-free and that there are trade-offs among sources.

2.5.1 Estimated Cost of a Catastrophic Tanker Oil Spill

As mentioned in the previous section, increased imports of oil via tanker increase the risk of major spills near sensitive areas and population centers. BOEM assumes a catastrophic event could involve an ultra large crude carrier (ULCC). Specifically, BOEM assumes a tanker of 550,000 deadweight tonnage and a maximum cargo of 3.52 million barrels grounding within 50 miles of shore and releasing up to 1.76 million barrels of its cargo. ULCCs offload at the Louisiana Offshore Oil Port and it would be highly unlikely that the spill would occur closer than 50 miles to shore. The largest event in the near shore GOM would likely be a spill from an Aframax tanker headed towards the Houston Ship Channel after lightering in the Western or Central GOM. The maximum spill volume in that case would most likely be 384,000 barrels. Therefore the cost estimates for a catastrophic tanker oil spill are applied to an oil spill of 384,000 barrels for the low case and 1.76 million barrels for the high case.

For a catastrophic tanker spill in the GOM, BOEM estimates that the lower volume 384,000 barrel spill would cost between $2.3 and 3 billion. In the event of the higher discharge case, where 1.76 million barrels are lost, BOEM estimates the cost to be between $10.7 and $13.5 billion..

2.6 SUMMARY

In the aftermath of the 2010 *Deepwater Horizon* event, BOEM considers the potential impact of low-probability/high-consequence oil spills more explicitly in its assessments of future exploration, development, and production activities on the OCS. Regulatory changes and industry best practices have reduced the likelihood of spill occurrence, but a decision as to whether or not to proceed with proposed lease sales necessarily carries with it the risk, however slight, of a catastrophic oil spill, regardless of the scope of the decision. This document primarily addresses environmental and social resources and activities that could be affected by a catastrophic oil spill. However, as explained above, a decision not to lease also carries with it risk from tankers carrying imported oil to replace OCS production or from other energy substitutes needed in the absence of a Program.

Chapter 3 Non-monetized Impacts

The net benefits analysis captures the most significant costs and benefits associated with new OCS leasing that can be reliably estimated and monetized. However, there are other potential impacts that are not as readily monetized and/or difficult to measure. The following sections outline some of the impacts, which are not monetized in the analysis, but discussed qualitatively.

3.1 Greenhouse Gas Emissions

In addition to calculating air emissions factors for six different air pollutants (NO_x, SO_x, particulate matter with a diameter of 10 or less microns [PM_{10}], $PM_{2.5}$, carbon monoxide [CO], and VOCs), the OECM calculates the level of emissions for three GHGs (carbon dioxide, methane, and nitrous oxide) that would be emitted "upstream" under the production and transport of resources in both the program and the No Sale Option. The OECM estimates of discharges stemming from the No Sale Option includes emissions from the overseas production of oil and gas imported to the U.S. and from the round-trip tanker voyages necessary to transport the oil to the U.S., as these emissions may have an impact on the U.S. due to the global nature of GHGs.

However, the OECM does not estimate a monetary value of the damages of the GHG emissions from production and transport and those costs are not incorporated in the net benefits analysis. The main reason for not incorporating those costs is that benefits and costs in the net benefits analysis are assessed at the domestic and national level, not at a global scale. For example, the air quality module in the OECM examines, among other impacts, adverse human health effects associated with increases in ambient $PM_{2.5}$ and ozone concentrations in the program area where they occur. Additionally, consumer surplus estimates from the *MarketSim* model are constrained to the national level. However, GHGs are concentrated on a global scale such that the resulting effects cannot appropriately be isolated for inclusion in the net benefits analysis.

Due to these differences in the way these costs are incurred (i.e., domestically versus globally), the social and environmental costs associated with GHGs are examined separately in the report, *OCS Oil and Natural Gas: Potential Lifecycle Greenhouse Gas Emissions and Social Cost of Carbon*. In the report, the downstream impacts caused by the consumption of oil and gas (that is, beyond the initial exploration, production, and transport of resources) are also analyzed.

For information on climate change impacts related to GHGs, refer to Chapter 4 of the Final Programmatic EIS (BOEM 2016b).

3.2 Onshore Infrastructure

Another category of environmental and social cost which is not monetized in the net benefits analysis is the development of onshore infrastructure that directly supports offshore oil and gas activities. In general, the net benefits analysis only considers the impacts associated with extracting resources and transporting them to shore. BOEM recognizes that additional environmental and social costs can occur as the result of onshore development and considers them qualitatively in this Chapter. The majority of these costs are too uncertain to model quantitatively at this stage given uncertainty surrounding the type, quantity, and location of infrastructure needs as well as the unknown mitigation measures that other permitting agencies will implement to minimize the environmental impact of any onshore support activities. As noted in the Final Programmatic EIS (BOEM 2016a), BOEM is not the permitting or regulatory agency for onshore development. Further, it is difficult to accurately estimate the specific onshore infrastructure which is a direct result from this Five-Year Program decision. Much onshore infrastructure may be used for existing oil and gas activity onshore or in state waters, other industrial activity near the coasts, or from the energy market substitutes associated with the absence of a sale in a program area.

The net benefits analysis does include the air quality impacts from onshore pipeline construction associated with development in the Chukchi Sea Program Area. These impacts are relatively foreseeable (as an onshore pipeline will be required to connect the Chukchi Sea to TAPS) and relatively straightforward to monetize (as the same air quality modeling done in the OECM can be applied to this project). However, the net benefits analysis does not consider other environmental impacts of the pipeline.

In general, construction or development of onshore infrastructure can cause changes in air quality, impacts from reductions in coastal marshland, the value of ecosystem services lost (e.g., flood protection), or impacts to water quality. Onshore infrastructure and the possible impacts are discussed in more detail in the Final Programmatic EIS (BOEM 2016b). The following is a list of the different types of onshore infrastructure, which are generally associated with offshore oil and gas operations:

- Port Facilities: Major maritime staging areas for movement between onshore industries and infrastructure and offshore leases.
- Platform Fabrication Yards: Facilities in which platforms are constructed and assembled for transportation to offshore areas. Facilities can also be used for maintenance and storage.
- Shipyards and Shipbuilding Yards: Facilities in which ships, drilling platforms, and crew boats are constructed and maintained.
- Support and Transport Facilities: Facilities and services that support offshore activities. This includes repair and maintenance yards, supply bases, crew services, and heliports.
- Pipelines: Infrastructure that is used to transport oil and gas from offshore facilities to onshore processing sites and ultimately to end users.
- Pipe Coating Plants and Yards: Sites that condition and coat pipelines used to transport oil and gas from offshore production locations.
- Natural Gas Processing Facilities and Storage Facilities: Sites that process natural gas and separate its component parts for the market, or that store processed natural gas for use during peak periods.
- Refineries: Industrial facilities that process crude oil into numerous end-use and intermediate-use products.
- Petrochemical Plants: Industrial facilities that intensively use oil and natural gas and their associated byproducts for fuel and feedstock purposes.
- Waste Management Facilities: Sites that process drilling and production wastes associated with offshore oil and gas activities.

Any anticipated onshore infrastructure growth is dependent on existing infrastructure in each region and changes in future offshore drilling. The level of existing onshore infrastructure and amount of new infrastructure varies among the three areas: the Arctic, Cook Inlet, and GOM.

While the development of onshore infrastructure to support offshore oil and gas operations could cause environmental and social costs, there would also be developmental economic benefits associated with the construction and operation of the facilities, which are similarly not included in the net benefits analysis.

3.2.1 Onshore Infrastructure Impacts in the Arctic Region

The Arctic is characterized by extreme remoteness, long arctic winters, and low population densities. In general, the region has little onshore infrastructure to support offshore oil and gas operations. However, the onshore area near the Beaufort Sea Program Area has a developed oil and gas industry with infrastructure to help support adjacent land and state water operations. Additional onshore infrastructure may also be developed in the region as a result of existing leases.

In general, the nature and magnitude of the impacts associated with onshore infrastructure development in the Arctic would depend on the level and location of the new construction and any mitigation or other requirements from permitting agencies.

The net benefits analysis does consider the environmental and social costs related to the air emissions of laying additional onshore pipeline adjacent to the Chukchi Sea Program Area. This onshore pipeline is assumed to be approximately 300 miles and connect the Chukchi Sea with the TAPS pipeline near Prudhoe Bay. More information on the calculation of these impacts is included in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a).

While the net benefits analysis does not include estimates of most environmental and social costs of onshore infrastructure construction, it also omits national economic “costs” that could be considered beneficial. For example, as indicated in Chapter 8 (Equitable Sharing Considerations) , construction and maintenance of infrastructure will produce employment, income, and tax revenues. Likewise, the net benefits analysis does not include such potential downstream effects as the reduction in TAPS tariffs that would result from OCS production.

3.2.2 Onshore Infrastructure Impacts in the Cook Inlet Program Area

The onshore areas surrounding the Cook Inlet Program Area are diverse and include a wide range of business and business support services for a variety of industries, including the well-developed oil and gas industries associated with state lands and waters. Due to a long history of oil and gas development in State waters, it is anticipated that existing infrastructure in Cook Inlet would accommodate oil and gas development as a result of new leases under this Program. As such, the extent of the impacts associated with oil and gas activities would depend on their specific location within the vicinity of Cook Inlet. Much of the basic onshore support and processing infrastructure necessary to support the anticipated levels of activity are already in place within the Cook Inlet, but these transport, loading, and storage capabilities may require expansion or retrofitting to handle an increased volume of produced crude oil.

If new infrastructure were needed, it would be built either as infill within an existing industrial or port area or within an area recently designated for this type of development. A greater impact on the existing physical landscape would be experienced in those areas not already used for oil and gas production.

Additional environmental analysis required by applicable permitting agencies would be conducted before the expansion or development of any additional onshore infrastructure.

3.2.3 Onshore Infrastructure Impacts in the GOM Program Area

The GOM region has a well-developed web of infrastructure already in place as a result of decades of offshore oil and gas activity in the region. The lease sales proposed under this Five-Year Program will likely not require additional infrastructure as additional production will fill spare capacity at current facilities. If additional production exceeds capacity at these facilities, the additional demand may be met by equipment upgrades or expansions at existing facilities. Any new or expanded facilities will be subject to environmental review and the impacts of such infrastructure will be thoroughly analyzed by applicable permitting agencies. This analysis will provide a more accurate assessment of the impacts as additional information is revealed on the location and scope of any new infrastructure.

Given the uncertainty in scope and location of new or expanded onshore infrastructure facilities, onshore infrastructure is not quantified in the net benefits analysis (with the exception of environmental costs associated with changes in air quality resulting from consutruction of an onshore pipeline to transport oil from the Chukchi Sea Program Area). However, this information on the relative nature of the necessary onshore infrastructure in each program area is provided for the Secretary to consider in her decision on the size, timing, and location of the lease sales proposed in the 2017–2022 Program.

3.3 Passive Use Values

In general, the net benefits analysis includes cost estimates of many types of use values, but does not include some values that would be associated as passive use values (also referred to as non-use values). Evidence of passive use values can be found in the trade-offs people make to protect or enhance environmental resources that they do not use. Passive use values exist under both the program and under the energy substitutes that would be necessary under the No Sale Option.

Within the net benefits analysis, certain passive use values are not estimated. The various types of passive use values are:

- Option value means that an individual’s current value includes the desire to preserve the opportunity to use a resource in the future.
- Bequest value refers to an individual’s value for having an environmental resource available for his or her children and grandchildren to experience. It is based on the desire to make a current sacrifice to raise the well-being of one’s descendants. Bequest value is not necessarily equivalent to the value of any information gained as a result of delaying leasing activities.
- Existence value means that an individual’s utility may be increased by the knowledge of the existence of an environmental resource, even though the individual has no current or potential direct use of the resource.
- Altruistic value occurs out of one individual’s concern for another.

A large body of literature discusses studies of these values. Estimating passive use values via stated preference surveys, such as the contingent valuation method, requires significant time and resources, and has been subject to scrutiny regarding the validity of results due to their hypothetical nature (i.e., survey respondents express values but are not required to actually pay) (Roach and Wade 2006). While best practices have improved the implementation of these methods over time through integration of validity and scope tests (Shaw and Wlodarz 2013), these methods remains resource-intensive processes.

To the extent that some passive use values exist in the literature, their ability to be transferrable to the BOEM context is probably quite limited. The values were developed using stated preference techniques and the results from such analyses are often highly dependent on the resource and specific context (which would include resource conditions, possible improvements or degradation as a result of policy changes, payment vehicles, etc.). If one were interested in evaluating the extent to which households or individuals hold passive use values (or a bequest value in particular) for OCS oil and gas resources, original empirical research would need to be conducted because a benefit transfer approach would not be appropriate given the importance of the specific context for stated preference studies. Total economic value studies (passive use values are part of total economic value) are time consuming and expensive to conduct. These types of studies are most appropriate to conduct in situations where the resources under consideration are unique, where a set of defined changes to the resource can be easily identified, and where the resource(s) are not typically bought and sold in markets. It is not clear this is the case for OCS resources. OCS oil and gas resources are not unique and they are readily bought and sold in markets.

More discussion on the ecological components not included in the net benefits analysis is in the section *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development* - *Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a).

3.4 Additional Impacts from Non-Catastrophic Oil Spills

While the net benefits analysis does quantify the costs of animal mortality and lost habitat from an oil spill through habitat equivalency analysis (where costs are estimated in terms of the anticipated expense to restore or recreate damaged habitat), it does not quantify the values above the restoration cost at which society may value the damaged resource (e.g., it does not monetize the impacts to unique resources). These costs are not monetized in the net benefits analysis, but additional information is provided in *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development* - *Volume 1: The 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015a) and *Forecasting Environmental and Social Externalities Associated with Outer Continental Shelf (OCS) Oil and Gas Development – Volume 2: Supplemental Information to the 2015 Revised Offshore Environmental Cost Model (OECM)* (BOEM 2015b).

Further, the model does not include ecological costs associated with the use of dispersants or the air quality costs associated with response vessel activity in the event of an oil spill. Those responding to an oil spill may apply chemical dispersants to affected waters to enhance natural dispersion of spilled oil by reducing surface tension at the oil/water interface, increasing the likelihood that wave motion will break the oil into small droplets that are more easily dissolved into water. The use of dispersants can often be controversial, as they may impact marine species and the environment, particularly in shallow waters (ITOPF 2011).

The impacts of dispersants and response vessel activity are not currently incorporated in the OECM. Adding such impacts to the model would require more detailed data on the likelihood of response activity in a given spill and an estimate of the likely impacts associated with dispersant use. While estimates of potential use could potentially be derived based on historical experience, detailed data relating their use to specific impacts are not readily available.

3.5 Additional Ecological Impacts

As discussed, the net benefits analysis includes monetized impacts to ecological resources through oil spills, but does not monetize the impacts to these resources from general operations. For example, it does not capture costs to habitats or organisms from waste cuttings and drilling muds deposited on the ocean floor near offshore structures; auditory impacts and vessel strikes to marine mammals; or water quality impacts associated with produced water discharged from wells or non-oil discharges from platforms and vessels. BOEM continues to monitor research on these topics for incorporation in future revisions to the net benefits analysis.

3.6 Benefit of National Energy Security

Over the last 50 years, U.S. oil and gas demand, supply, and prices have increasingly shaped U.S. national energy policy concerns and national security issues. As crude oil is used as a source of energy for many goods, services, and economic activities throughout the U.S. economy, supply disruptions and increases in energy prices are felt by nearly all U.S. consumers.

Concerns over energy security stem from the importance of crude oil and natural gas within U.S. economic markets and the energy supply disruptions that can occur due to the characteristics and behavior of the global crude oil supply market. The externalities associated with oil supply disruptions—economic losses in GDP and economic activity—have been shown to be greater for imported oil than domestically produced oil. Increased domestic oil production can boost the share of stable supplies in the world market while increased oil imports, often from unstable regions, can have the opposite effect (Brown and Huntington 2010). Increased oil and gas production from the OCS can help mitigate the impact of supply disruptions and spikes in oil prices on the U.S. economy, mitigating economic downturns as well as the amount of U.S. dollars sent overseas from purchases of crude oil imports.

3.7 Benefit from Improved U.S. Trade Deficit

Chapter 1 of the 2017–2022 PFP provides a discussion of energy's importance in the balance of payments and trade, with emphasis on their relationship to OCS production and imported oil. In particular, large expenditures on crude oil imports can stifle economic activity and slow down domestic economic growth, as well as impact the rate of U.S. inflation and reduce the real discretionary incomes of U.S. consumers (CRS 2010). Domestic production of oil from the OCS reduces the amount of oil that must be imported from abroad, thereby mitigating the effect high domestic energy expenditures may have on the U.S trade deficit.

3.8 Benefits for Recreational Fishing and Diving

Obsolete offshore oil and gas platforms can be converted to artificial reefs to support marine habitat. In the GOM, where the seafloor consists mostly of soft mud and silt, artificial reefs and platforms can provide additional hard-substrate areas for a variety of species. The benefits of artificial reefs are well documented and may increase the density of fish species around platforms as compared to natural reef sites (BOEM 2012b).

Gulf coast states have recognized the potential importance of such aquatic structures to marine species and local activities. The artificial reef programs in these states, as part of the Rigs-to-Reefs program, have worked to facilitate the permitting, navigational requirements, and liability transfer for decommissioned and reefed rigs in Federal and state OCS waters. The reduction in pressure on natural surrounding reefs and the impact on local industries, and to a certain extent, the greater economy, illustrates the potential environmental and social benefits artificial reefs may provide. More information on the artificial reefs and the state programs are included in Appendix A-4 of *Gulf of Mexico OCS Oil and Gas Lease Sales: 2012–2017 Final Environmental Impact Statement* (BOEM 2012b). The leasing from this Five-Year Program is expected to increase the number of platforms in the GOM, providing increased gathering areas for commercial and recreational fishermen and steering reefing activities towards artificial reef locations that tend to decrease navigational and commercial fishing burdens while increasing the attractiveness of sites for recreational and commercial use.

Chapter 4 Fair Market Value Analysis: WEB2 Methodology

As described in Section 10.1.2 of the 2017–2022 PFP, at the Program stage, BOEM considers how the timing of offering program areas for oil and gas leasing affects their value through the use of a hurdle price analysis. The hurdle price is the price below which delaying exploration for the largest potential undiscovered resource field in the sale area is more valuable than immediate exploration.[25] BOEM uses the WEB2 (When Exploration Begins, Version 2) model to calculate the hurdle prices associated with each program area. This paper provides additional information on the methodology behind WEB2 and the approach used to calculate the hurdle prices.

BOEM's calculation of the hurdle price here is refined from what was published with the 2017–2022 Proposed Program. The Proposed Program analysis itself was greatly revised from the previous calculations included in the 2012–2017 Program analysis and the 2017–2022 DPP analysis. The DPP analyses calculated the hurdle price based on consideration of NEV, but the analyses in the Proposed Program and PFP have been expanded to include the environmental and social costs of OCS activities and considers the optimal timing of leasing decisions based on net social value (NSV). NSV is the NEV less the environmental and social costs. This will be described in more detail in this chapter.

4.1 WEB2 Calculations

BOEM uses the WEB2 model to calculate the social value of offering leases now versus waiting. WEB2 computes the social value of immediate leasing versus delays of 1 through 10 years. BOEM considers leasing in this 2017–2022 Program to be immediate leasing (2017), a one-year delay (2018) and up to a four-year delay (2021). Delays of 5 to 10 years are considered as leasing in 2022 through 2027, which are after the end of the 2017–2022 Program. If the social value of delaying leasing until the next program (2022–2027) is higher than leasing at any time during this current period, then delaying the area until the next program could be optimal. This analysis is conducted for each program area. Given the size and distinct nature of the GOM Program Area, BOEM considers the shallow and deepwater regions separately.

WEB2 calculates the NEV as:

$$NEV = Q(P - V) - F$$

In this equation, Q is the quantity of resources, P is price, V is variable costs, and $F$is fixed costs. Both the quantity of resources and price inputs are random variables determined by the WEB2 model. BOEM then adjusts the NEV for the environmental and social costs associated with development to calculate the NSV.

[25] All else being equal, the largest field tends to have the highest net value per equivalent barrel of resources, making it the least likely field to benefit from a delay in being offered for lease. BOEM used the 90th percentile field size as the approximate largest field size available in each program area.

$$NSV = NEV - ESC$$

In this equation, ESC is the estimate of environmental and social costs. BOEM then compares the expected value (denoted by the symbol E_{t+1}) of the NSV if an area is available for lease immediately with the expected value of the NSV if leasing is delayed. WEB2 calculates the expected social value in the next period (in time, $t + 1$) based on the choice to lease or wait in the first period (e.g., "What is the value tomorrow of my choice to explore today?"). The social value of leasing is calculated as:

$$SV_L = E_{t+1}[NSV(r_s)|lease\ in\ t]$$

The social value of waiting is calculated as:

$$SV_W = E_{t+1}[NSV(r_s)|wait\ in\ t]$$

In this equation, SV_L is the social value of leasing and SV_W is the social value of waiting. The calculation of social value under both the leasing and waiting scenarios are discounted at the social discount rate, r_s. This analysis uses a social discount rate of 3 percent.

To calculate the hurdle price, the WEB2 is run iteratively for various (higher) start prices until the first start price is found, at which leasing in 2017–2021 produces a higher NSV than leasing in 2022 or after. This price then becomes the hurdle price, the price below which waiting to lease is optimal when compared to leasing immediately.

4.2 Hurdle Price Assumptions

To calculate the hurdle price, BOEM employs various assumptions to estimate the value of the resources and how this value might change with delay. This section outlines the assumptions for resources, prices, private costs, and social costs.

4.2.1 Resource Assumptions

The first step in calculating hurdle prices is to identify the resource assumptions in each program area. WEB2 uses two separate resource assumptions in calculating the potential field size in a region: the probability that the lessee finds resources during exploration, and, if resources are found, the expected field sizes. BOEM assumes a 20 percent success rate for exploratory drilling. BOEM uses an approximation of the largest field size in each program area as the expected field size. The largest field size, all else being equal, tends to have the highest net value per equivalent barrel of resources and thus would be the most profitable in a sale and provide the lowest hurdle price. The reason for focusing on just the largest field is that the decision criterion using the hurdle price is intended to be conservative, to avoid the risk of withholding, on economic grounds, an area that might have at least one field that ought to be developed immediately. This decision is appropriate at the programmatic level where the decision is simply made whether or not to include an area in the Five-Year Program, not to make a final decision on holding the sale, its configuration, and its financial terms.

For the purposes of determining hurdle prices, BOEM analyzed the distribution of expected undiscovered field sizes associated with each program area based on results from BOEM's *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2016*

(BOEM 2016; herein referred to as the 2016 National Assessment) estimates at the mean probability. In general, the 2016 National Assessment addresses undiscovered resources in a framework of field size and probability. The field size framework is provided by the United States Geological Survey (USGS) field size classes, which enables grouping fields. For example, there might be two fields in a range of 2 to 4 million BOE (MMBOE); three fields in the next class covering 4–6 MMBOE; and so on. The corresponding largest field size from which hurdle prices are calculated were then associated with the 90th percentile of the field size distribution. The 90th percentile field size provides a practical estimate of the largest field size by eliminating the tails of the resource distribution. Although the 90th percentile corresponds to a 1 in 10 chance of discovering a field that exceeds the largest field size shown, this percentile constitutes a reasonable assumption based on known discoveries and/or analog information in each program area. Table 4-1: Assumed Largest Field Size by Program Area shows the estimated largest field size in each program area.

Table 4-1: Assumed Largest Field Size by Program Area

Location	Assumed Largest Field Size (MMBOE)
Beaufort Sea	113
Chukchi Sea	190
Cook Inlet	175
Shallow GOM	44
Deep GOM	90

Note: The 90th percentile is used for the assumed largest field size to avoid extreme values created by the statistical process used to generate the distribution of field sizes. For the Chukchi Sea and Beaufort Sea Program Areas, the resulting designated field size represents only the oil portion of the largest field given that gas prospects are not projected to be economic.

Approximating the largest undiscovered field size as the 90th percentile field is retained from the Proposed Program, and that document explains improvements made to earlier analyses for the 2012–2017 Program and the 2017–2022 DPP.

4.2.2 Price Assumptions

The WEB2 model incorporates a specific type of price model that is appropriate for the analysis of real options for commodities like oil and gas. The price model in WEB2 represents the range of possible future prices generated by a specific algorithm that models a mean-reverting stochastic process. In this formulation, the change in price from one time to the next is random, and the probability of a step up or down reflects a tendency for movement toward the mean level. WEB2 calculates price as the following:

$$P_{t+1} = P_t[\frac{T_{t+1}}{P_t}]^{\alpha}\varepsilon_{t+1}$$

Where: P_t is the real price in time t; T_{t+1} is the real mean trend price in time t; α is the reversion rate; and ε_{t+1} is a random term. The three inputs to this price model are the trend price, the reversion rate, and the volatility that is incorporated in the random term. The mean trend gives the price level in each year that market prices tend to revert to after they have randomly moved off of trend. In other words, if the actual price in 2017 happens to be in the vicinity of $50/boe and the trend price is specified as a flat $90, then the model represents the 2018 price by combining an upward tendency – since the 2017 price is below the mean trend—and a random factor that might be upwards or downwards. The real price in time t = year of lease sale is the "start price" of this process. In the application to the issue of the timing of lease sales, theWEB2 model is solved for the lowest "start price" price that provides a greater net social value from leasing in the current program versus waiting until the future. That solution is what is called the hurdle price. If the market price at the time of leasing happens to be lower than the calculated hurdle price, then a delay of leasing is indicated.

For the hurdle price analysis, BOEM assumed that the trend price was the BOE price combining $90 per barrel (bbl) of oil and $4.80 per thousand cubic feet (mcf) of natural gas in 2017 dollars. Following the mean-reversion framework, we assumed that the starting price (which is equivalent to the hurdle price) will revert to the trend price at a rate of 12 percent of the difference per year. The volatility (that is, the annualized standard deviation) is assumed to be 32%. These parameters were estimated by BOEM by a regression analysis of historical oil and gas prices, where the regression model was the mean-reverting model.

The price model specification used for this hurdle price analysis differs from the 2012 hurdle price calculations. In prior analyses there was no representation of random prices tending to revert to a mean trend; instead, the start price simply grew annually at a fixed rate. The revised price model conforms to the widely used mean reversion framework, which corresponds to current price expectations from different forecasting agencies.

An important aspect of WEB2 is that resource estimates and prices are input as BOE values. The gas-oil ratios in each program area varies significantly, so market and mean trend prices per BOE in each area reflect that area's weighting of the gas and oil price based on the area-specific gas-oil ratio. See Section 4.3, Hurdle Price Results, for more detail.

4.2.3 Private Cost Assumptions

Once the largest field size is set (approximated by the 90th percentile field size), the WEB2 model requires estimates of the private exploration and development costs associated with that field. Development and production cost inputs for the WEB2 model are consistent with those used in the calculation of the NEV in Section 5.3 of the 2017–2022 PFP. The costs used for both analyses are based on the commercial Que$tor cost modeling system, data collected by BOEM for the socioeconomic analysis of the Five-Year Program (i.e., the economic impact model MAG-Plan), and cost estimates used in tract evaluations. BOEM identified an approximate level of infrastructure required for the size of the largest field in each program area and calculated total costs based on the individual components. A lessee's decision to develop is determined in WEB2 by the net present value of the project. In calculating the net present value of a project for its developer, a real discount rate of 7 percent is used. Note that this is different from the social discount rate, 3 percent, that is used to calculate the net social value of revenues and social costs.

4.2.4 Environmental and Social Cost Assumptions

For the 2017–2022 Program, BOEM has expanded its consideration of the hurdle price analysis to incorporate the environmental and social costs that society incurs from OCS development. The 2012 hurdle price analyses considered only how NEV changed based on the decision to lease now or delay leasing. This current analysis now considers NSV in making the same decision. To incorporate NSV, BOEM needs an estimate of the environmental and social costs that might occur from the development of the largest field size.

BOEM estimates the environmental and social costs of the exploration, development, production, transport, and decommissioning of the largest field size in each program area using the OECM. The environmental and social costs include air emissions, oil spill risks, etc. They are described in more detail earlier in Section 1.5, Incremental Environmental and Social Costs. These costs are subtracted because they are anticipated to be incurred from the traditional annual input measures of the NEV (e.g., gross revenues and private costs). By including environmental and social costs into the hurdle price analysis, the hurdle prices increase slightly over what they would be solely focusing on NEV. The increase is due to the fact that the inclusion of environmental and social costs changes the NEV into a lower NSV, thereby providing a larger proportional effect of higher prices on the underlying value of a given field size. The amount that the hurdle price changes owing to the inclusion of environmental and social costs in each program area varies depending on the relative magnitude of these costs and the estimate of NEV in each area. Table 4-2: Estimated Environmental and Social Costs of Assumed Largest Field Size by Program Area shows the estimate of the NEV and the ESC of the assumed largest field size in each program area. These values are the sum of the NEV and ESC over the life of the field assuming immediate leasing in each program area. Both values are discounted at a rate of 3 percent.

Table 4-2: Estimated Environmental and Social Costs of Assumed Largest Field Size by Program Area

Program Area or Location	Assumed Largest Field Size (MMBOE)	Estimated Net Economic Value ($millions)	Estimated Environmental and Social Costs ($ millions)	Estimated Net Social Value ($ millions)
Beaufort Sea	113	$697	$15	$683
Chukchi Sea	190	$1,287	$16	$1,271
Cook Inlet	175	$1,209	$16	$1,193
Shallow GOM	44	$183	$61	$122
Deep GOM	90	$504	$49	$455

Notes: The largest undiscovered field size is approximated as the 90th percentile field from the 2016 National Assessment field size distribution. The 90th percentile is used to avoid extreme values created by the statistical process used to generate the distribution of field sizes. For the Chukchi Sea and Beaufort Sea Program Areas, the resulting designated field size represents only the oil portion of the largest field given that gas prospects are not projected to be economic. The estimated net economic value and environmental and social costs are shown with no delay in leasing, but with the future revenues discounted at a rate of 3 percent.

The estimate of environmental and social costs is lower in the Alaska program areas, given the differences in impact categories in those regions. A large portion of the ESC in the GOM Program Area comes from impacts on beach recreation, which do not occur in Alaska. Further, the air quality impacts in the non-Alaska regions have greater costs given the proximity to population centers. The Alaska program areas do include impacts not included elsewhere such as subsistence, but these are of a smaller value than those monetized in the other regions.

The analysis of this section does not cover substitute sources of energy that would be required to fulfill domestic demand in the absence of new OCS production, as discussed in Section 5.3 of the 2017–2022 PFP, and these energy sources have their own environmental and social costs. As shown in Chapter 5 of the 2017–2022 PFP, the environmental and social costs of the energy substitutes are greater than those estimated from OCS production. If such "*incremental*" environmental and social costs were subtracted from the NEV in the hurdle price analysis, the result would likely be *lower* hurdle prices because by postponing OCS production, the energy sector would likely turn, for now, to more environmentally harmful sources of energy.

4.3 Hurdle Price Results

The lease operator was modeled as having flexibility to time the investment in exploration, and separately, any investment in development. Each such decision is based on the contrast of the expected current value of the project with exploring or developing versus waiting. The operator must, of course, make any decision to explore or develop during the initial period of the lease.[26] If it would be optimal to wait until the end, the operator must decide then to act or let the lease expire. Because WEB2 includes a random price diffusion process and accounts for the operator's options to explore or wait, and/or to develop a discovery or wait, it can be called a "real options" model.

Table 4-3: NEV Hurdle Prices shows the estimated hurdle price if only NEV is considered. The calculated hurdle prices are in 2017 dollars and should be compared with actual prices in 2017. Such a comparison would allow for areas that are more profitable to include in the current program versus waiting until a future program purely with the consideration of NEV.

Note that due to doubts about Arctic natural gas reaching a market, the hurdle prices for the Beaufort Sea and Chukchi Sea Program Areas were determined using only the oil portion of BOE that would be sold. For these areas, the BOE trend price is only the oil portion (which is both $90 per barrel and $90 per BOE). Should higher prices such as those considered in the high price scenario in Section 5.3 of the 2017–2022 Proposed Program be realized, natural gas price may exceed its transport cost, and may eventually be sold under the program.

[26] In cases where a lessee is awarded the lease, the lease rights are issued for a limited term called the initial period (also known as the primary term). The initial period promotes expeditious exploration while still providing sufficient time to commence development.

Table 4-3: NEV Hurdle Prices

Program Area or Location	Largest Undiscovered Field (MMBOE)	Natural Gas-Oil Ratio	Portion of Field BOE		NEV Hurdle Price
			Oil	Natural Gas	Price per BOE
Beaufort Sea	113		100%	*	$34
Chukchi Sea	190		100%	*	$33
Cook Inlet	175	1.19	83%	17%	$20
Shallow GOM	44	8.67	39%	61%	$18
Deep GOM	90	1.60	78%	22%	$32

Notes: The largest undiscovered field size is approximated as the 90th percentile field from the 2016 National Assessment field size distribution. The 90th percentile is used to avoid extreme values created by the statistical process used to generate the distribution of field sizes. For the Chukchi Sea and Beaufort Sea Program Areas, the resulting designated field size represents only the oil portion of the largest field given that gas prospects are not projected to be economic.

Table 4-4: NSV Hurdle Prices expands on the basic hurdle price calculation shown in Table 4-3: NEV Hurdle Prices by adding the hurdle prices as calculated using the NSV. To calculate these hurdle prices, the environmental and social costs from Table 4-2: Estimated Environmental and Social Costs of Assumed Largest Field Size by Program Area are considered in the value calculation. The impact of adding the environmental and social costs vary by program area. For example, the shallow water portion of the GOM Program Area has the largest increase in hurdle price when the environmental and social costs are included. This is the case given that the environmental and social costs are a larger portion of the original NEV than they are for any of the other areas. As such, it takes a higher starting hurdle price to prompt including an area in a program versus waiting for future programs. The Chukchi Sea and Cook Inlet Program Areas do not have a significant difference in NSV hurdle price over the NEV price. This is due to the relatively small environmental and social costs and the large NEV expected from both areas given the high oil content and resource potential.

Table 4-4: NSV Hurdle Prices

Program Area or Location	Largest Undiscovered Field (MMBOE)	Natural Gas-Oil Ratio	Portion of Field BOE		NSV Hurdle Price
			Oil	Natural Gas	BOE
Beaufort Sea	113		100%	*	$35
Chukchi Sea	190		100%	*	$33
Cook Inlet	175	1.19	83%	17%	$20
Shallow GOM	45	8.67	39%	61%	$22
Deep GOM	134	1.60	78%	22%	$34

Notes: The largest undiscovered field size is approximated as the 90th percentile field from the 2016 National Assessment field size distribution. The 90th percentile is used to avoid extreme values created by the statistical process used to generate the distribution of field sizes. For the Chukchi Sea and Beaufort Sea Program Areas, the resulting designated field size represents only the oil portion of the largest field given that gas prospects are not projected to be economic.

The hurdle prices in Table 4-4: NSV Hurdle Prices are then compared with forecasts of future oil and gas prices. BOEM compared the BOE hurdle prices with those from the EIA's *Annual Energy Outlook* . Table 4-5: Forecast BOE Prices in 2017 shows the forecasted oil and natural gas prices for 2017 (in 2017 dollars) from each of these forecasts as well as the calculated BOE price associated with each Program Area. As discussed, in the Chukchi Sea and Beaufort Sea Program Areas, BOEM assumes that only the oil portion of the field will be produced and the natural gas portion will be re-injected. As such, the BOE price is equivalent to the oil price in those program areas. To calculate the BOE price in the other areas, the natural gas-oil-ratio is used.

To further explain the calculation of the weighted BOE price from the oil and natural gas price forecasts, consider the deep water GOM. As shown in Table 4-4: NSV Hurdle Prices, in the deepwater GOM for example, the natural gas-oil ratio means there are approximately 1.6 mcf of natural gas for every barrel of oil produced. This equates to, on average, one BOE in the field consisting of 78 percent oil and 22 percent natural gas. Using the BOEM forecast oil price from Table 4-5: Forecast BOE Prices in 2017, the BOE price is calculated as 78 percent the oil price ($50.00 * 0.78 = $39.00) plus 22 percent of the price of a BOE of natural gas[27] ($3.21 * 0.22 * 5.62 = $3.97). Therefore, a BOE in the deepwater GOM is approximately $43 (slight differences exist due to rounding).

Table 4-5: Forecast BOE Prices in 2017

Program Area/ Location	EIA's 2017 Forecast		
	Oil	Gas	BOE
Beaufort Sea	$50.00	$3.21	$50.00
Chukchi Sea			$50.00
Cook Inlet			$44.42
Shallow GOM			$30.61
Deep GOM			$42.92

Notes: For the Chukchi Sea and Beaufort Sea Program Areas, only the oil portion of the field is expected to be produced. Thus, the BOE price is equivalent to the oil price in these program areas. All prices shown in this table are in 2017 dollars.

The forecast for 2017 prices indicates that the weighted BOE prices will be above the NSV hurdle prices shown in Table 4-4: NSV Hurdle Prices for all of the program areas. However, BOEM notes that the calculation of the hurdle prices are highly dependent on the assumptions about the future trend price of oil and natural gas and on the rate at which prices revert to that trend. BOEM's initial calculations indicate that a faster reversion rate would lead to lower hurdle prices. For example, BOEM's initial calculations for the deepwater GOM showed that assuming prices would revert at a rate of 15 percent (instead of what was assumed in this analysis as 12 percent) would lead to a hurdle price approximately $20 per BOE instead of the $34 found using the 12 percent reversion rate. BOEM found that the hurdle price results were relatively less responsive to the mean reverting trend price than they are to the reversion rate. Given the sensitivity of the assumptions to the results, BOEM is continuing to evaluate refinements to the analysis. Further refinements and analysis will be conducted at both the PFP stage and at the individual lease sale stage for each sale within the Program. Revised assumptions or price trends could affect the decision of whether to offer an area at any of those stages.

[27] On a thermal basis, 5.62 mcf of natural gas provides the same heat content as a barrel of oil. Thus, a BOE of natural gas is 5.62 mcf of natural gas.

Of course, the hurdle price calculation does not include every facet of uncertainty and is not intended to accurately predict future price paths. However, the hurdle price analysis still provides a useful screening tool to consider areas for inclusion in the 2017–2022 Program. The EIA price forecast estimates that prices in 2017 will be above the hurdle prices shown in Table 4-4: NSV Hurdle Prices. As such, this analysis suggests that it is worth including all of these program areas in the Proposed Program. BOEM will consider refinements to the analysis for the 2017–2022 PFP stage and the individual lease sale stage for each sale within the Program. Revised assumptions or price trends could affect the decision of whether to offer an area at any of those stages. However, this would only be one criterion that the Secretary would consider in evaluating a particular program area or lease sale. There are great benefits in the stability of a lease sale schedule. The decision to delay leasing an area would have to be considered in conjunction with these other factors not monetized in the hurdle price analysis before a final decision is made.

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