Coastal Marine Institute

A Review and Update of Supplemental Bonding Requirements in the Gulf of Mexico

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ABSTRACT

In the mid-1980s, large oil and gas companies began to divest their portfolio of properties in the Gulf of Mexico (GOM). As smaller companies built up their production assets, concern was raised that the U.S. government was exposed to financial risk if abandonment responsibilities were not met. To ensure that the government is adequately protected from incurring costs associated with offshore lease abandonment, the Minerals Management Service (MMS) required operators to post a supplemental bond if at least one working interest owner on a lease does not satisfy a minimum threshold financial capacity. A supplemental bonding formula was developed in the early 1990s based upon the estimated cost to decommission offshore infrastructure. The purpose of this study is to update the supplemental bonding formula to account for changes in the cost environment and technology over the past two decades, and to present risk-adjusted alternatives to represent the uncertainty inherent in the implementation of any formula mechanism. We review the objectives of the MMS supplemental bond program and provide a set of guidelines in formula development. MMS policy on supplemental bond requirements is reviewed along with background information on decommissioning operations. The objectives of a bonding formula are described along with the tradeoffs that occur in all formula mechanisms. The philosophy of making rational tradeoffs between cost and risks is common throughout the offshore industry, and our recommendation is to select bonding levels in a risk-adjusted basis to balance the need of the government to minimize its decommissioning exposure at an acceptable level of risk. The factors that impact government decommissioning exposure is highlighted, along with detailed cost estimates of plugging and abandonment, structure removal, and site clearance and verification operations.

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EXECUTIVE SUMMARY

The objective of the MMS bonding program is to ensure that all entities performing activities under the jurisdiction of the MMS provide or demonstrate adequate financial resources to protect the U.S. Government from incurring any financial loss. Each lease in the GOM region is reviewed to ensure the working interest owners have adequate financial coverage to provide for the performance of all lease obligations when the designated operator and/or the lessees cannot fulfill their requirements on rent, royalties, environmental damage, cleanup and restoration activities, abandonment and site clearance, and other lease obligations.

To ensure compliance with regulatory and lease requirements and to protect the government from incurring oil and gas lease abandonment costs, the MMS requires companies to post a general bond for all leases and supplemental bonds for leases without at least one party deemed "financially capable."

A general bond is required on all leases to ensure compliance with rent, royalties, environmental damage and clean-up activities not related to oil spills, abandonment and site-clearance. Additional security in the form of a supplemental bond is required when the cost to meet all potential present and future lease abandonment obligations exceeds the amount of the general bond unless one of the current lessee(s) can demonstrate the financial capability to meet these obligations. The supplemental bond formula currently employed was developed in the early 1990s to cover well plugging and abandonment, structure removal, and site clearance operations, and has not been adjusted for changes in the cost environment or technology over the past two decades. The purpose of this report is to update the supplemental bond formula in a risk-adjusted manner to more accurately represent the cost and government exposure associated with decommissioning activities. This is our recommended formula for setting future bonding levels in the GOM.

In Chapters 1 and 2, we describe the characteristics of offshore decommissioning and review the objectives of the MMS supplemental bond program. A set of general guidelines to follow in formula development are enumerated.

In Chapter 3, the MMS supplemental bond formula is updated with a recommended risk-adjusted mechanism across each of the three main stages of decommissioning. The procedures, assumptions, and risk-adjusted levels of an updated supplemental bond formula are presented.

The risk-adjusted tableau in Chapter 3 was derived from empirical data collected from various industry sources. In Chapters 4-6, the source data of the three main stages of decommissioning are reviewed along with detailed cost analysis.

The removal of the topside facilities, deck, conductors, piles, and jacket is the core of all decommissioning projects and typically the most expensive stage. In Chapter 4, we examine the cost of removal operations in the shallow-water GOM based on 133 structure removals performed by Tetra Applied Technologies LLC between 2003-2008. Our data set consists of 120 projects and represents $178 million in expenditures, the largest single data set of decommissioning operations analyzed in the GOM to date. We summarize cost statistics for removal operations and describe the factors that impact cost. Structure preparation, pipeline abandonment, and removal cost across several levels of categorization are developed as well as first-order regression models for removal cost.

Wells are drilled to explore for, delineate, and produce hydrocarbon reservoirs. At the end of their useful life, all wells are permanently abandoned and cement plugs placed across each producing horizon. The purpose of plug and abandonment (P&A) is to prevent the migration of fluids from the wellbore and establish a permanent barrier to the existing geologic formation. In Chapter 5, we assess trends in P&A costs in the GOM over the time period 2002-2007 based on a sample of 1156 wells performed by Tetra Applied Technologies LLC. Descriptive statistics are summarized and the impact of scale economies is investigated. Relations that estimate the cost of P&A activities based on the number of wells in a job and the number of days of service is derived.

In Chapter 6, descriptive statistics based on 308 net trawling jobs performed in the GOM between 2001-2005 are presented. Site clearance and verification (SC&V) is the last stage of an offshore decommissioning program where oil and gas related debris is removed in the vicinity of the structure and the site is verified clear. A variety of techniques may be used to perform SC&V operations, but net trawling and diver survey are the most common in the GOM. SC&V costs are summarized relative to structure type and water depth categories. Factors that impact the cost of SC&V operations are discussed.

1. BACKGROUND AND REMOVAL STATISTICS

1.1. Introduction

The U.S. government sells the right to explore for hydrocarbons and develop tracks on the Outer Continental Shelf[1] (OCS) at periodic sealed-bid auctions. The bidding variable at these auctions is a cash payment, or "bonus," which must be paid to the government before the lease becomes effective. Once the lease becomes effective, a rental and royalty payment is required.[2] Operators buy the right to extract natural resources on federal lands subject to royalty and rental payments, a commitment to operate in an environmentally sound manner, and to remove facilities at the end of the useful life of the lease. When bidding on properties, operators incorporate many factors in their evaluation, such as the probability of a commercial discovery, expected reserves and development cost, expected level of competition, and an estimate of the cost to remove the facility. The government accepts less money up-front in the bonus payment in exchange for the commitment on the part of the operator to remove facilities if the lease results in production.

The MMS is required to ensure that current and future development of offshore oil and gas resources are performed in a way that is operationally safe and safeguards the environment. Once production facilities reach the end of their service life, MMS is obligated to ensure that decommissioning operations protect the safety of workers and environmental integrity, while also ensuring that the decommissioning operations conform to the regulations and do not create future residual liability.

From the operator's point of view, decommissioning represent a cost to be incurred in the future, while from the government's perspective, decommissioning represents a risk of noncompliance and potential financial liability. A general bond is required on all leases to ensure compliance with rent, royalties, environmental damage and clean-up activities not related to oil spills, abandonment and site-clearance, and other lease obligations. The level of activity on the lease determines the amount of the general bond. When the cost to meet lease obligations exceeds the amount of a general bond, and the lessee cannot demonstrate the financial capability to meet these obligations, a supplemental bond is also required. Current MMS policy requires a lessee to submit a supplemental bond when the MMS estimate of cumulative potential end-of-lease liability is greater than 25% of the lessee's net worth.

On each lease, the MMS considers all lessees, operators,[3] and operating rights[4] interest owners to be jointly and severally liable for all lease obligations. In other words, a company that sells its property remains liable for decommissioning if the current owner(s) do not comply with the

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[1] The OCS is the part of the continental shelf beyond the line that marks State ownership; i.e., offshore lands under Federal jurisdiction.

[2] The rental fee is on a per-acre basis and royalty is equal to a specified fraction of the value of hydrocarbons produced if the drilling program is successful.

[3] The operator is the individual, partnership, corporation, or other business entity having control or management of operations on a leased area or portion thereof. The operator may be a lessee, designated agent of the lessee, or holder of rights under an MMS-approved operating rights assignment.

[4] Operating right is a leasehold interest that entitles the holder to conduct drilling and related operations, as well as responsibilities for the cost of development and operation of the property, and all lease liabilities created or established during ownership.

terms of the lease. If a property has current or previous working interest owners who are not financially capable, or if a property does not have any previous owners, then the property will be put up for sale. If a property is marginal or decommissioning liability is greater than the value of the lease, then it is unlikely that a buyer will be found for the property. Decommissioning commitments, nonetheless, have to be fulfilled. If the cost of decommissioning turns out to be greater than the supplemental bonds on the lease, then there is a problem, since the U.S. government is the party of last resort and would incur financial liability. Supplemental bonding is meant to protect the U.S. government against incurring financial liability, but as we observe above, it is one link in a long chain of events that have to occur before triggering liability.

Each producing lease in the OCS represents a different level of decommissioning risk to the government. Risk events may be triggered by occurrences specific to a few participants, such as a bankruptcy or blowout, or by events that impact several operators simultaneously, such as a hurricane event. Fortunately, the default rate of operators in the Gulf of Mexico (GOM) has historically been extremely low and the impact on operations to date minimal. Over the past two decades, only two operators in the GOM were unable to meet their decommissioning obligations. In both cases, because there was a previous record title holder of the lease who was financially capable, the federal government did not have to incur any expense (Kruse, 2007). In recent years, however, an increasing number of operators have approached the MMS to seek compensation when the cost of decommissioning operations exceeds their posted bond levels. Of course, the government does not compensate operators if their bonding levels are not sufficient to meet their commitments, but it is interesting to note the occurrence of such events and the implications on current supplemental bonding levels.

The MMS approach to computing end-of-lease liability is defined according to an empirically-derived formula (Table A.1) and has worked successfully in the past, but because the bonding formula is calibrated to projects performed in the early 1990s, there is an obvious need to update the formula to reflect current operating costs and technology. As part of a review of bonding requirements in the GOM, the MMS proposed that the supplemental bond formula be updated using more recent data and a risk-adjusted assessment be considered when setting levels. The authors were tasked with providing a recommendation for an updated supplemental bonding formula.

The purpose of this study is to discuss the tradeoffs and objectives in setting supplemental bonding levels in the GOM. We motivate the framework of our analysis and develop a risk-adjusted methodology. In this chapter, we summarize decommissioning activity in the GOM and review the legislative history of bonding requirements. Federal regulations associated with decommissioning are also outlined. We conclude by characterizing the general nature of offshore abandonment operations.

1.2. Development and Decommissioning Activity in the GOM

1.2.1. Exploration and Development Wells

The number of exploration and development wells drilled in the GOM on an annual basis is shown in Figure A.1. Exploratory (wildcat) wells are drilled in an area with no known hydrocarbon reserves, while delineation and development wells are used to delineate a known deposit and then produce it. A successful development well will produce hydrocarbons, while ‘success” for an exploratory well may not actually result in production. Onshore, discovery wells are usually turned into producers, while offshore, successful exploration wells may be plugged and abandoned because the location is not optimal for field development. Successful exploratory wells are usually protected with a caisson or well protector, and as delineation wells are drilled, the field will be developed with additional infrastructure. From 1947-2007, a total of 35,660 wellbores[5] have been drilled in the GOM: 13,665 exploratory wells and 21,875 development wells (Figure A.2).

Drilling activity dropped off significantly in 2007 due in large part to the intense recovery efforts associated with the 2005 hurricane season. The last time drilling activity in the GOM fell below 400 wells drilled was in 1992 (the year another hurricane - Andrew - entered the gulf). The ten-year (1995-2005) average number of wells drilled in the GOM is 501, while in 2006 and 2007, a total of 408 and 332 wells were drilled. The total number of exploratory and development wells by water depth category is shown in Table A.1. Since the mid-1990s, deepwater exploratory wells have played an increasingly important contribution to the total number of wells drilled.

1.2.2. Temporary and Permanent Abandonment

All producing wells pass through the same initial and final state, beginning with completion and ending with abandonment. After a well is drilled to target depth, it is evaluated to determine if it should be completed. Eventually, all wells become inactive because of diminished economic returns due to marginal oil and gas production or mechanical problems with the completion or downhole production equipment. When a well stops producing, it may either be shut-in (SI), temporarily abandoned (TA), or permanently abandoned (PA).

When an exploratory well is under evaluation or when a flowing well is no longer economic to produce, the well will often be temporarily abandoned. Wells destroyed by a hurricane will be TA’d if operators intend to re-enter the well at a later date. Wells that may be sidetracked for redevelopment may also be TA’d. Operators shut-in wells for minor problems and before the appearance of a hurricane. Shut-in operations are easier to perform and to re-enter at a later date, but require a stringent inspection schedule. TA operations are more expensive to perform but require less inspection and oversight. The cost to re-enter a TA well is also more expensive than a SI well. At the end of the life of a lease, when lease production ceases, all the wells on the lease must be permanently abandoned. SI and TA wells are thus considered a temporary or transitory stage, while a PA well is the terminal state of a wellbore.

The annual number of TA and PA operations in the GOM is shown in Figure A.3. The large number of TA operations in 2006 and 2007 is the result of the 2005 hurricane season. To date, about 19,167 wells have been PA’d and 2,000 wells TA’d (Figure A.4). The number of wellbores that remain to be PA’d is the difference between the total number of wells (exploration and development) drilled and the cumulative number of permanent abandonments. The inventory of wellbores circa 2007 that remain to be PA’d currently stands at about 16,500 (Figure A.5).

[5] Wellbores are defined as the original borehole. Sidetrack and bypass wells are not counted in this tally.

1.2.3. Structure Type

Offshore structures are designed for a particular field, and are built according to specific design criteria for the metocean and environmental conditions that exist at a specific location. Shallow water structures, defined as development in water depths less than 1,000 ft, primarily employ caissons, well protectors, and fixed platforms. A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well conductor and is the minimum structure for offshore development. Structures that provide support through a jacket to one or more wells with minimal production equipment and facilities are referred to as a well protector. Production from caissons and well protectors is sent to host processing facilities on a fixed platform prior to being transported to shore. Fixed platforms are large structures that include facilities for drilling, production, and workover operations. In deepwater, floating structures and subsea completions are required because economic and engineering limitations rule out steel jackets that pass through the entire water column. A few dozen spars, semisubmersibles, and tension-leg platforms are used in deepwater development in the GOM, as well as several hundred subsea systems.

1.2.4. Structure Installation

The number of structures installed in the GOM by structure type is depicted in Figure A.6. The "other structures" category shown in Figure A.6 refers to deepwater[6] structures such as spars and tension leg platforms. Over the past decade, the number of structures installed per year has ranged between 73 and 161 (with average 119, standard deviation 27). To date, nearly 7,000 structures have been installed, with about one-third of the installations being caissons (Figure A.7).

1.2.5. Structure Removal

When lease production ceases, all oil and gas infrastructure on the lease will be removed. The first offshore structures in the GOM were removed in the early 1970s, and by 1990, the number of removals began to exceed 100 (Figure A.8). Over the past decade, the number of structures removed has ranged from 76 to 194 (with average 136, standard deviation 36). In total, nearly 3,000 structures have been removed in the GOM, almost half of which are caissons (Figure A.9). In Table A.5, the number of removals by structure type and water depth is depicted. About half of the installed unmanned fixed platforms have been removed, compared to only 10% of manned installations.

1.2.6. Active Structures

The number of active (existing) structures in the GOM is shown in Figure A.10. There are currently 3,838 active structures: 2,324 fixed platforms, 380 well protectors, 1,091 caissons, and 43 other structures. The number of removals began to equal or exceed the number of installations in the early 1990s, and during this time, the inventory of active structures has remained relatively stable. Currently, the average number of removals slightly exceeds the number of installations, which will likely accelerate in the future as fewer, larger structures, in the deepwater are installed, and a larger number of smaller structures supporting marginal fields, are abandoned. The cumulative number of installed, removed, and active structures in the GOM is shown in Figure A.11.

[6] Although deepwater structures only number a few dozen (Table A.2), they are currently responsible for over 70% of the total oil production in the GOM.

1.3. Outer Continental Shelf Bonding Program

The objective of the OCS bonding program is to ensure that all entities performing activities under the jurisdiction of MMS provide or demonstrate adequate financial resources to protect the U.S. government from incurring any financial loss.

1.3.1. Bond Requirements

Each lease is reviewed to ensure the lessees or co-lessees have adequate financial coverage to provide for the performance of all lease obligations when the designated operator and/or lessees cannot fulfill their requirements. Securities ensure that operators fully comply with all regulatory and lease requirements, including rents, royalties, environmental damage cleanup and restoration activities, abandonment and site clearance, and other lease obligations.

All leases and right-of-ways[7] (ROW's) are required to have a general bond regardless of the financial strength or supplemental bond waiver status of any of the lessees. The supplemental bond program was developed to provide the federal government additional protection against incurring costs involved specifically with abandonment and site clearance activities. The MMS determines the need for additional security by reviewing a lessee's financial ability, record of meeting obligations, and projected financial strength (MMS, 2001).

1.3.2. General Bonds

The designated operator of a lease is required to provide a general lease surety bond or pipeline ROW bond before the MMS will issue a new lease or approve a lease, ROW assignment, or operational activity plan.

Leases are designated as no operations, exploration, or development, and incur general bonds based upon the level of activity: (a) No Operations – a $50,000 lease-specific or $300,000 area-wide general bond with no MMS-approved operational activity plan; (b) Exploration – a $200,000 lease-specific or $1 million area-wide general bond for leases in a proposed exploration plan (EP) or a significant revision to an approved EP; (c) Development – a $500,000 lease-specific or $5 million area-wide general bond for leases in a proposed development and production plan (DPP) or a significant revision to an approved DPP. All ROW permittees must have a $300,000 ROW pipeline bond (MMS, 2001).

A review of bonding coverage is performed when operators request for a change of designated operator; an initial EP; an initial DPP; an initial Development Operations Coordination Document (DOCD); or a significant revision (i.e., a supplemental plan) to an approved EP, DPP, or DOCD; or request an assignment of a lease with an approved EP, DPP, or ROW plan.

1.3.3. Supplemental Bonds

The supplemental bond program was developed to protect against liability associated with decommissioning activities. Using historical data from the period 1989-1993, the MMS

[7] A right-of-way usually refers to a grant by MMS for the construction and maintenance of a pipeline and associated structures on the OCS.

developed a bond level to ensure that the cost incurred in plugging and abandoning wells and removing facilities was covered.

The MMS computes end-of-lease liability by estimating the cost to plug and abandon all boreholes, scrap and remove onshore all structures, and site clear and verify a lease according to the algorithm shown in Table A.1.

A lessee's supplemental bonds, cumulative liabilities, and financial strength may be reviewed at any time, but generally, initial reviews are conducted when a lessee submits an EP for approval. Subsequent reviews are conducted when a lessee requests MMS approval of: an assignment of the lease record title interest (lessee of record), or a portion of the record title interest in a lease; significant revision to an approved EP; DPP or a significant revision to an approved DPP; DOCD or a significant revision to an approved DOCD; application for a pipeline ROW or modification to an existing pipeline ROW; assignment of record title of an existing or approved pipeline ROW permit; and significant revision to an approved pipeline installation plan (MMS, 2001).

1.4. Federal Regulations

The operator is required to submit form MMS-124, "Sundry Notices and Reports on Wells," and receive approval prior to plug and abandonment operations. Form MMS-124 contains information on the reason the well is being plugged, a description of the work requirements, and an assessment of the expected environmental impacts of the operation and the procedures and mitigation measures taken to minimize such impacts (Federal Register, 2002). Before beginning operations, the MMS District Supervisor is required to be notified at least 48 hours prior to the operation.

All wellheads and casings are required to be removed to a depth at least 5 m (15 ft) below the mudline unless the District Supervisor approves an alternative depth. The District Supervisor may approve an alternate removal depth if wellhead or casing would not become an obstruction to other users of the seafloor or area; the use of divers and the seafloor sediment stability pose safety concerns; or the water depth is greater than 800 m (2,640 ft). The requirement for removing subsea wellheads or other obstructions may be reduced or eliminated when, in the opinion of the District Supervisor, the wellheads would not constitute a hazard to other users of the seafloor.

A pipeline may be abandoned in place if it does not constitute a hazard to navigation, commercial fishing operations, or unduly interferes with other uses in the OCS. Pipelines abandoned in place need to be flushed, filled with seawater, and plugged with the ends buried at least three feet below the mudline.

To remove a platform from OCS waters, a structure removal application and site clearance plan must be submitted to the MMS, and if explosives are to be used for cutting, it is necessary to receive an Endangered Species Act Section 7 consultation. The piles, conductors, and caissons that attach the jacket to the seafloor and serve as a conduit to the hydrocarbon reservoir must also be severed and removed at least 5 m (15 ft) below the mudline. Strict regulations govern the manner in which explosives are used offshore to mitigate the environmental impact (Federal Register, 2002).

All abandoned well and platform locations in water depths less than 91 m (300 ft) must be cleared of all obstructions present as a result of oil and gas activities. For clearance purposes, locations are defined as follows:

- Exploratory or delineation wells drilled with a Mobile Offshore Drilling Unit: 300 ft (91 m) radius circle centered on the well,
- Single-well caissons: 600 ft (183 m) radius circle centered on the well,
- Platform: 1,320 ft (402 m) radius circle centered on the platform geometric center.

Platforms and single-well caissons in water depths less than 91 m (300 ft) are trawled for clearance verification. The MMS preferred verification technique is to drag a standard trawl net across 100% of the site in two directions. In some cases, alternative site verification techniques such as side scan sonar or documentation of sweep assembly results have been used. At the conclusion of the operation, a completion report is submitted to the MMS detailing the removal operation and certifying that the site has been cleared.

1.5. Characteristics of Offshore Decommissioning

1.5.1. All Offshore Fields Have End-of-Life Decommissioning Cost

The value of a lease at any point in time is determined by its production rate, hydrocarbon prices, remaining reserves, upside potential, operating cost, and decommissioning liability. When the market value of a field is zero, the discounted value of the remaining reserves is equal to the discounted cost of abandonment.

As long as the property value of a lease exceeds one year of cash flow, enough value usually remains in the lease that other buyers will have an interest in acquiring the property (Haag, 2005). When the value of a lease becomes negative or falls below one year’s cash flow, the pool of quality buyers shrinks considerably, and it is unlikely that the lease can be divested on a stand-alone basis.

When the value of a producing lease turns negative, the discounted value of the remaining reserves is less than the discounted cost of abandonment. At this point in time, the operator may try to divest the lease or abandon the property. As long as the lease is producing in commercial quantities, the operator may defer abandonment, because it is unlikely that a suitable pool of buyers will be found. Marginal properties are sometimes packaged with other higher-value leases and sold together.

1.5.2. Each Decommissioning Project Is Unique

Offshore structures are designed for a particular field, and are built according to specific design criteria for the metocean and environmental conditions that exist at a specific location. At the end of its economic life, or because of the occurrence of an exogenous event, the structure will be decommissioned according to federal requirements.

Each decommissioning project requires a case-by-case evaluation and is similar to field development in the sense that the project is unique in terms of the requirements of the operation, equipment used, site and market conditions at the time of the activity, contract terms, and operator preferences.

Decisions about when and how an offshore structure is decommissioned involve issues of environmental protection, safety, cost, and strategic opportunity. The factors that influence the timing and method of removal are complicated and depend as much on the technical requirements and cost as on the preferences established by the contractor, scale economies, and the scheduling of the operation.

1.5.3. Decommissioning Occurs In Distinct, Temporally Disjoint Stages

Decommissioning operations occur in stages over disjoint time frames. Each stage typically involves several types of activities.

1.5.3.1. Project Management and Engineering

The engineering planning phase of decommissioning consists of a review of all contractual obligations and requirements from lease, operating, production, sales, or regulatory agreements. A plan is developed for each phase of the project, and the process of surveying the market for equipment and vessels is initiated. Engineering personnel may be sent to the site to assess the work requirements, and the project management team will report on the options available, including the scope of work that needs to be performed and how best to prepare the bid. Permits are secured from the MMS to plug and abandon wells and pipelines, remove structures, and verify site clearance. Permits are also required in the form of an Incidental Take Statement if explosives are to be used in the removal process. If cleaning fluids or NORM wastes are to be pumped into nonproducing wells, additional permits will need to be acquired. How bids are structured and the level of competition at the time the contract is let play important roles in determining the cost of the operation.

1.5.3.2. Wellbore Plugging and Abandonment

The purpose of well plugging is to provide downhole isolation of hydrocarbon zones, protect freshwater aquifers, and prevent migration of formation fluids within the wellbore or the seafloor. All unplugged and temporarily abandoned wells on a lease must be permanently P&A'd within 1 year after the lease terminates or if the MMS determines that the well poses a hazard to safety or the environment or is not useful for lease operations and not capable of profitable oil or gas production. Dry holes or wells that do not contain hydrocarbons are usually P&A'd immediately, while wells that require evaluation or have problems in production are temporarily abandoned. Producing wells are shut-in or plugged when operators determine that additional reserves cannot be commercially produced from the well.

1.5.3.3. Platform Preparation

After plugging and abandonment activities are complete, the structure is prepared for removal normally by a crew paid on a dayrate. An inspection is made to determine the condition of the structure and identify potential problems. Depending on the water depth, inspections are performed using divers or a remotely-operated vehicle. On deck, the crew flushes and cleans all piping and equipment that contained hydrocarbons. All modules to be removed separately from the deck are cut loose, and the piping, electrical, and instrumentation interconnections between modules are cut. Work needed to prepare the modules for lifting is also done at this time. The fluids and agents used to purge and clean the vessel must be disposed by pumping them downhole through an injection well or to storage in tanks and onshore disposal in accord with MMS regulations. Equipment and other metallic debris are sent onshore to recycle or scrap, while non-metallic debris is sent as waste to a landfill.

1.5.3.4. Pipeline Abandonment

According to MMS regulations, pipelines with diameters > $8\frac{5}{8}$ inches that are installed in water depths < 200 ft are buried at least 3 ft below the mudline.[8] For lines $8\frac{5}{8}$ inches and smaller, a waiver of the burial requirement may be requested (Cranswick, 2001). Upon the cessation of operations, a pipeline may be abandoned in place if it does not constitute a hazard to navigation, commercial fishing operations, or unduly interferes with other uses in the OCS. Pipeline abandonment operations are fairly routine. Pipelines abandoned in place are flushed, filled with seawater, cut, and plugged with the ends buried at least 3 ft below the mudline. Remotely operated vehicles with electrohydraulic tools perform the cutting operations or divers do the work. Most pipelines in the GOM are abandoned in place and very few complete removals have been performed (Pulsipher, 1996).

1.5.3.5. Conductor Removal

Conductor severing and removal may take place as part of P&A activity or during the structure removal operation. The conductors may contain multiple strings of well casing grouted together and with voids. Mechanical casing cutters, abrasive water jets, or explosives are used to make the cuts at the designated elevation. Conductor length drives the number of sections to be cut, stored, and offloaded, which in turn influences the type of cargo barge required.

1.5.3.6. Structure Removal

The removal of the topside facilities, deck, conductors, piles, and jacket is the core of all decommissioning projects, and frequently the most expensive stage. If wells are complex or large in number, however, or problems arise in plugging, then wellbore abandonment may also be a significant contributor to the total cost of decommissioning. Production equipment and deck modules need to be placed on a cargo barge and returned to shore for scrap or reuse; conductors, casing string, and piling need to be cut, pulled, and removed from the ocean floor at least 15 ft below the mudline; and the jacket needs to be lifted and taken onshore, to another location, or to an artificial reef site. If the structure resides within a reef planning site, topple-in-place or partial removal may be a viable option. Explosives are prepared and installed in the piles and skirt piles. If the mud plug inside the piles is not deep enough to allow the explosive charge to be placed at the required depth, the mud plug is jet/air lifted. As an alternative to explosives, abrasive cutters and mechanical cutting can also be used to sever the piling. Foundation piles are cut 5 m (15 ft) below the seabed and left in place. Several removal options may be available to operators.

[8] Any length of pipeline that cross a fairway or anchorage in federal waters must be buried at least 10 ft below mudline for a fairway and 16 ft below mudline across an anchorage area.

1.5.3.6.1. Complete Removal

In a complete removal, the structure is removed by lifting in one piece or in sections, depending on the size of the jacket and the capacity of the lift vessel. The jacket is transported ashore for recycling, storage, refurbishment, or disposal, or transported to an artificial reef site.

1.5.3.6.2. Partial Removal

In a partial removal, the jacket is cut to a depth such that an unobstructed water column allows safe navigation. The depth of the cut is specified by U.S. Coast Guard regulations. Abrasive cutting or divers are used to sever the critical jacket members since explosives are not permitted in open water. The bottom part of the jacket remains attached to the seafloor, while the top part may be taken ashore for recycling, storage, refurbishment or disposal, or placed next to the bottom portion of the jacket on the seabed as a reef component. A structure that is partially removed must receive a state permit that establishes the site as an artificial reef.

For additional discussion of the activity requirements associated with structure removal, see (Manago and Williamson, 1997; Pulsipher, 1996).

1.5.3.6.3. Toppling In Place

A structure that is toppled-in-place involves cutting the jacket legs so that the jacket collapses under its own weight, or by using a pull barge to provide the forward momentum. An unobstructed water column of a given depth is again specified by U.S. Coast Guard regulations, and the operator must receive a permit that establishes the site as an artificial reef.

1.5.3.7. Site Clearance and Verification

Site clearance and verification (SC&V) is the last task to occur in decommissioning. The operator has 60 days from the time the structure has been removed to clear the site and verify clearance. Clearance deals with the removal of oil and gas related debris that has accumulated on the seafloor at the production site, while verification is used as a check to ensure that the site is clear.

1.5.4. Decommissioning Timing Is Defined by Regulatory Requirements

The timetable for decommissioning is determined by whether the lease on which a structure resides is producing. If a non-producing structure is on a producing lease, owners have greater flexibility in scheduling cleanup and decommissioning activities, since the inactive structure can be held until the lease stops producing. If an inactive structure is not on a producing lease, and does not serve a useful economic purpose, then the owner has one year after lease production ceases to decommission the structure and return the seafloor to its condition prior to development.

1.5.5. Decommissioning Operations Are Usually Low-Tech and Routine

Decommissioning operations are for the most part a low-tech operation that has not seen significant changes over the last several decades. The physical requirements of decommissioning and the processes involved with the operation have stayed relatively constant over time, although some environmental regulations (e.g., use of explosives, monitoring requirements) and financial commitments (e.g., financial capacity definition) have tightened. The “rigless” approach to P&A

has been an important cost reduction driver, but additional technological progress is not expected to play a significant role in reducing cost in the future.

Decommissioning operations are generally routine and involve standard equipment and procedures. There are no significant barriers to practice or entry, so new firms can form relatively quickly and easily if demand and supply imbalances create the conditions for new business ventures to enter the market.

1.5.6. Decommissioning Operations Occur Over Short Time Scales

Typically, decommissioning operations are completed over time scales that range from a few days to several weeks. SC&V activities usually take several days to perform, while plugging a well and removing a structure may take one to three weeks or longer. P&A and SC&V are usually performed on a dayrate basis, with the primary cost component due to the variable cost from the vessel dayrate and equipment rentals. Labor and fuel are secondary cost components. Removal operations are often performed under turnkey ("lump sum") contracts with weather risk held by the operator.

1.5.7. Decommissioning Operations Usually Have Low Carrying Cost

Since decommissioning represent a liability to operators with no promise of increased cash flow, operations are usually not fast tracked. Federal regulations require that all infrastructure on a lease be removed within one year after production on the lease ceases, so until lease production ceases, idle wells and structures often accumulate until sufficient scale exists to economically and efficiently perform the operations (Kaiser and Mesyanzhinov, 2004). In the 2005 hurricane season, operators learned that carrying a large inventory of inactive structures and wellbores carries the risk of potentially significantly higher decommissioning cost if destroyed or severely damaged. The risk of significantly higher cost should provide sufficient incentive for operators to decommission structures that no longer serve a useful economic purpose.

1.5.8. Many Factors Influence Decommissioning Costs

The cost to decommission offshore structures is influenced by a large number of variables and events that vary across each stage of the operation, and as in most offshore activities, tend to depend on factors that cannot be modeled accurately. Competition levels for services are usually high throughout the year, but seasonal variations often exist. High competition stabilizes cost in normal markets, and supply and demand forces are a dominant factor impacting cost volatility. General inflationary pressures are also present, but usually not to the extent impacting the upstream industry.

Factors that impact cost can be measurable and certain (e.g., water depth, location, structure type, structure weight, etc.) or unobservable and uncertain (e.g., well complexity, vessel dayrates, weather conditions, problem wells, amount of planning, etc.). Because the number of factors and events influencing each project is large and unpredictable, it is not possible to identify a primary set of factors that determine outcome in each instance. The factors that determine cost will vary with each operation.

1.5.8.1. Plugging and Abandonment

Various factors contribute to the cost of plugging activities, including plug types and lengths; well access; completion status (single or multiple); well type (wet tree or dry tree); perforation and casing cutting plans; size and amount of casing removed; well depth; age; water depth; nature and quantities of material used; environmental conditions and complications at the time of the operation; contracting strategy; contractor experience; and operational scheduling.

1.5.8.2. Structure Removal

The cost to remove an offshore structure depends on the weight and size of the structure; removal method; oceanographic and environmental conditions at the time of the operation; the lifting equipment used; method of pile cutting and severing success; number of conductors that have to be removed; diving requirements; water depth; environmental issues; reefing and reuse opportunities; strategic decisions; contracting strategy; potential for scale economies; operator and contractor experience; amount of planning time; supply and demand conditions for the vessels at the time of bidding.

1.5.8.3. Site Clearance and Verification

The amount of time involved to clear a site depends on the amount, size, and type of debris present; the location of the site; the equipment available to perform the operation; and the weather conditions at the time of the operation.

1.5.9. Independents and Majors Have Different Expectations, Requirements, and Cost Structures

Companies approach decommissioning from different operating philosophies and business models which may lead to different cost structures. Small companies tend to be cost-minimizers, while large companies tend to focus on risk management, and these alternative perspectives will impact the cost of the operation. Large independents and majors often approach decommissioning in a planning intensive and comprehensive manner. Large companies tend to be concerned with potential future liabilities, and because they are usually faced with greater public and government scrutiny, approach projects with greater caution and different expectations and requirements. Independents tend to want to get the job done quickly and efficiently at minimum cost, and because their activity is generally subject to less scrutiny, may not plan as extensively as majors.

1.5.10. Catastrophic Failures Will Often Lead To Significantly Higher Decommissioning Cost

There are many risks in offshore production which may lead to catastrophic failure of a platform, such as blowouts, fire, explosions, collisions, storm destruction, and earthquakes. Fortunately, the occurrence of such events are relatively infrequent, and because the offshore environment is today better understood and subject to increasingly stringent design standards and regulatory requirements, most failures from extreme weather are the result of older design codes that did not specify an adequate deck height or similar criteria (Laurendine, 2008).

The risks associated with operating offshore are unavoidable and involve tradeoffs between costs and human and social consequences. The risk and cost involved in decommissioning destroyed infrastructure are higher than under normal conditions, often ranging between 5-50 times more than conventional abandonment, and in some cases, can be significantly[9] more expensive.

Structures destroyed in a hurricane are found lying horizontally on the ocean floor, often in a tangled web of steel. When a structure fails, the pipes that cased the wells will bend and may collapse. Debris over and around the wells must be cleared and vertical sections of pipe accessed before the wells can be plugged and abandoned. In extreme cases, an operator may have to access the vertical portion of the wellbore or drill a relief well to access the old wellbore. Seafloor debris is cut by divers or remotely operated vehicles (ROVs). Divers do the work with limited access and poor visibility, and the tasks are often complex and require the design of new tools. ROVs can reduce the need for divers, but in most cases, they are unable to perform all the operations required and are expensive to operate. Complete removal may not be technically feasible or may pose unacceptable risks to diver personnel. If the integrity of the platform is sufficient, the platform can be lifted and transported to shore or a reef site; otherwise, the toppled structure will have to be cut and removed in pieces, or dismantled at site in a manner that satisfies site clearance requirements (Kaiser and Kasprzak, 2008).

[9] Taylor's 8-pile fixed platform at Mississippi Canyon 20, for example, was destroyed by a mud flow incident during Hurricane Ivan. The structure collapsed and was moved 800 ft from its original location and submerged nearly 75% below the mudline. Estimates for cleanup operations have ranged up to $500 million (Taylor, 2007). Taylor has sold off all of their producing assets and leases, except the MC20 platform, effectively exiting the Gulf.

2. FORMULA GUIDELINES

2.1. Introduction

Rational tradeoffs between cost and risks is common throughout the offshore industry, and in this chapter we espouse a similar set of guidelines in the development of a bonding formula. The objectives of a bonding formula are described along with their tradeoffs. We advocate the selection of bonding levels that balance the need of the government to maintain its decommissioning exposure at an acceptable level of risk. We also highlight the factors that impact the government's decommissioning exposure. We begin with a brief review of cost estimation techniques to provide the motivation for the limitations inherent in all bonding formula.

2.2. Decommissioning Cost Estimation

2.2.1. Cost Categories

Most decommissioning operations occur in distinct stages, and the manner in which contracts are written across each stage and how activities are accounted for and reported determine what categories arise and how cost is allocated across category. Cost allocation methods vary with each project and contractor, but most decommissioning projects are described through the following categories:

- Project Management and Engineering
- Plugging and Abandonment
- Structure Preparation
- Pipeline Abandonment
- Conductor Removal
- Structure Removal
- Site Clearance and Verification
- Miscellaneous

Work activities typically fall across one or more categories, and may be classified within a common (miscellaneous) category, such as diving and cutting, debris removal, cleanup, catering, etc. or allocated according to prescribed measures. Structure preparation, pipeline abandonment, mobilization/demobilization, and conductor removal are often aggregated within the structure removal category, which leads to the following three categories:

- Plugging and Abandonment (P&A)
- Structure Removal (REM)
- Site Clearance and Verification (SC&V)

Structure removal is usually the largest cost category, contributing anywhere from 50-80% of the total cost of decommissioning, followed by plugging and abandonment (25-50%) and site clearance and verification (5-10%). On an individual project basis, substantial variation exists depending on time, location, and operator characteristics (Twachtman and Byrd, 2008). Plugging and abandonment cost can be substantial, for instance, depending on the number and complexity of the wellbores and well access, while clearance and verification rarely constitutes more than 5% of the total cost of any operation. Project management and engineering for integrated service providers may add 5-15% to the total cost of a project.

2.2.2. Cost Estimation Procedures

Decommissioning cost estimates can be performed in a number of ways: using engineering models, historical data, statistical relations, stochastic models, scaling rules, activity breakdown, and expert input. In practice, a variety of techniques are applied, depending on the requirements of the estimate, the time and resources available, and the experience of personnel. Models of the (de)construction process and market environment in which physical activities occur are used in cost estimation. The success of these models determines the success[10] of estimation.

Three approaches to cost estimation are described. The unit cost and statistical method are the most common and are in widespread use throughout the process and construction industries.

2.2.2.1. Engineering Method (*Unit Cost*)

In the engineering approach, technical personnel review the requirements of decommissioning, and with appropriate assumptions on equipment availability, dayrates, removal methods, disposal alternatives, and other factors, estimate the cost of the operation. The estimator breaks down (decomposes) each stage of the operation into a number of tasks that must be completed, and once these tasks are defined, a unit cost and time duration is assigned to each, similar to classic cost estimation techniques (Page, 1977). Unit cost and time duration are determined from market and historical data, expert opinion, and other sources. Total cost is determined by summing across all tasks that need to be performed. A separate contingency factor may also be incorporated in the calculation.

2.2.2.2. Statistical Method (Historical Data)

In empirical cost inference, historical data is analyzed to derive statistical cost functions which attempt to relate the cost of an activity to a primary set of attributes of the process. The comparative approach is used as a basis for analogy.[11] This approach is usually best suited for aggregate analysis and is most appropriate when a large number of estimates need to be derived and average characteristics are acceptable. The role of statistical inference is to estimate the best parameter values in an assumed cost function by means of statistics or regression analysis. Examples of decommissioning cost models based on correlating historical data with system descriptors are described in (Kaiser et al., 2003; Kaiser, 2006a).

[10] The cost model must also match the target of the application, particularly with respect to accuracy and the type of features one wants to distinguish. The selection of the features is guided by the requirements of the estimation and must be based on measurable characteristics.

[11] According to Webster, the comparative approach is "A form of logical inference, or an instance of it, based on the assumption that if two things are known to be alike in some respects, then they must be alike in other respects."

Statistical methods employ an empirical technique that relates cost data with one or more structure characteristics, such as structure type, weight, water depth, ownership, etc. Empirical equations fit data to assumed model forms.[12] Extrapolating the results of an empirically-derived equation to the future assumes that all the factors affecting performance in the past have the same cumulative effect in the future. This is a strong, and certainly, questionable assumption. The use of cost curves thus necessitates a set of assumptions regarding technology, regulatory policy, market issues, and the occurrence of exogenous events. The collective set of all these conditions, assumed constant for the time frame of analysis, is referred to as "stable technology, regulatory, and market conditions." Changes to any of the above-named factors have the potential to dramatically change both the cost and timing of decommissioning, which will impact the estimation results.

2.2.2.3. Operator Survey

Another approach to estimate decommissioning cost is to survey operators on their anticipated decommissioning liability. Operators account for dismantlement, restoration, and abandonment (DR&A) costs at various levels of the organization – on a well, field, property, and division basis, and for the company as a whole. The method of cost estimation depends upon the size of the asset inventory, operator experience, and various other factors. Methods range from conceptual engineering estimates to definitive engineering estimates, and may be evaluated annually, quarterly, semiannually, or whenever an event occurs that suggests revisions may be necessary.

A 2001 PricewaterhouseCoopers report provides an overview of the manner in which DR&A costs are accounted by the U.S. petroleum industry (Coe et al., 2001). Thirty companies responded to the 2001 survey from over 300 questionnaires. The average DR&A cost estimates per well for offshore properties are shown in Table B.1 categorized according to all respondents, successful efforts versus full costs accounting companies, and independent versus major classification.

There are advantages to a survey approach, since operators are expected to have superior knowledge regarding their decommissioning costs, but unfortunately, the variety of assumptions and techniques encountered among operators outweigh the potential benefits. According to FASB 143 (Kaiser, 2005), future decommissioning costs should be discounted to their present value, but with regard to platform disposition and timing, operators may assume economies of scale, scheduling benefits, reef placement, etc. that are not publicly disclosed.

2.2.3. All Decommissioning Cost Estimates Are Uncertain

All cost estimates are uncertain and are time, site, and location dependent, varying with the nature and complexity of the activity to be estimated. The level of uncertainty in cost estimation can range widely. The difference between the actual and estimated cost can vary from less than

[12] An alternative approach is to compute the average duration of an activity based upon historical data, and then to multiply the duration with an estimate of expected dayrates at the time the activity is expected to occur. In this case, the estimator will need to make assumptions regarding the expected supply and demand conditions in the region at the time of the activity. The level of uncertainty of this approach is likely to be comparable to the average cost approach, but because of the additional assumptions required, the empirical cost inference is preferred. We make no assertion that one method is superior to the other.

10% to over 100%, depending on the time and assumptions involved in the estimation, the success of the operation, and the occurrence of events outside the control of operators. In offshore decommissioning, a large number of uncertain and unpredictable factors contribute to variability, including the downhole and weather conditions, market supply and demand, and the extent of preparation. The causes of uncertainty are numerous, and often, the manner in which individual factors impact costs are intractable.

An additional complication is that data sources that are available for analysis are usually small, from a specific sector (or company) of the industry, and often fail to identify those factors which make each operation unique. We are thus limited in our ability to understand why costs behave in a particular way. Our ability to infer cost trends is similarly limited, and hence estimates of decommissioning cost are only indicative of general trends relative to a specific model environment and sample set, and should only be interpreted with an understanding of their limitations.

2.2.4. Decommissioning Costs Are Market-Driven and Dynamic

Decommissioning costs are not static, and will vary over time with the market conditions for vessels and labor, the market rates for scrap steel, and various other time-dependent factors. While decommissioning costs are impacted by general inflationary pressures, they are not as volatile as traditional construction activities in the upstream sector (e.g., fabrication, drilling), since there is no significant material usage (e.g., steel) required; the cost of chemicals, fuel, and other consumables[13] usually play a small role in the total cost of the operation; and the activities are usually of short duration and scheduled at opportunistic times for contractors. Decommissioning activities are specialized but can be performed by a wide sector of the industry, and there are no significant barriers to entry which would be expected to create abnormal cost pressures.

2.3. U.S. Government Decommissioning Exposure

2.3.1. Each Producing Lease Represents a Different Level of Decommissioning Risk

Each producing lease in the OCS represents a different level of risk to the government. When a company declares bankruptcy or cannot meet lease abandonment obligations, all the lease properties in which the company is a record title holder or holds operating rights, as well as all leases in which the company held previous interest, trigger a risk event.

For a company default to trigger government decommissioning liability, several events would have to occur simultaneously. We demonstrate the sequence of events that need to occur to generate government liability (Figure B.1).

The government faces the most risk from leases that do not have at least one financially capable current or previous working interest owner. In the event that a working interest owner cannot meet lease abandonment obligations, the responsibility of decommissioning would be shared among other working interest participants. If there are no other working interest owners of the

[13] For example, for P&A operations, cement and bridge plugs are consumables; for SC&V operations, un-repairable trawling nets and oxygen supply for divers are consumables. The cost of consumables is usually a small percentage of total cost.

property, or if the current owners, either individually or collectively, are not financially capable to meet the obligation, then any and all of the lease's previous owners would be required to assume responsibility. In the event that there are no previous record title holders able to meet the financial commitment of abandonment, the institutions that hold the company debt will try to sell the property to minimize their losses.

If the present value of lease production exceeds the expected cost of decommissioning, or has at least one year cash flow greater than abandonment liability, the lease may be sold to a third party who will produce until the economic limit and then assume decommissioning obligations. Otherwise, if the property is late in life and does not hold sufficient commercial reserves to cover the cost of abandonment, it is unlikely that a buyer will come forth. The value of the property and the level of production relative to decommissioning liability is another important element that determines risk exposure.

Finally, only in the event that the cost of decommissioning exceeds the posted bond level will the U.S. government be faced with decommissioning liability. If the cost of the operation falls below the posted bond, the government would hold no financial liability, since the costs are fully covered. If the cost of the operation exceeds the bonding level, then the government exposure would be the difference between the actual cost and posted bond.

2.3.2. Decommissioning Exposure Is a Function of Several Stochastic Variables

Each producing lease in the GOM can be considered to hold a certain amount of "decommissioning risk" to the government. The level of risk depends upon the number of current and previous record title holders and their financial capacity, the level of production relative to the cost of decommissioning, and the decommissioning expense relative to bonding requirements. Each event has a probability of occurrence which in most cases is difficult to compute.

2.3.2.1. Financial Capacity and Ownership Structure

The number of responsible parties associated with a lease and their collective financial capacity is a key determinant of the amount of decommissioning risk a lease holds. The ownership structure of oil and gas leases can be very complex. Transactions occur through farmouts, carveouts, acquisition and divestitures. Networking and overriding royalty interests create a multi-layered network of owners which serve as a protective mechanism for the government. With each additional user (i.e., owner) the probability that the government will be faced with decommissioning liability is reduced. Bankruptcy is not a common occurrence in the GOM, but it can and does occur. Leases that have been owned and operated by one company throughout its history present a special concern, since if at some point in time the company has financial difficulties there is no other party to which the lease would revert.

If a lease has more than one working interest owner, past or present, each additional party represent additional layers of protection for the government, and provide under normal conditions, a layer of security that ensures under most circumstances decommissioning operations will be performed without governmental financial involvement. One financially capable responsible party is usually sufficient to mitigate most of the risk exposure facing the government, but even if there is no single financially strong company, so long as the collective strength of parties is sufficient, this will also serve to mitigate nearly all the risk exposure. All current owners are jointly responsible. If there are no other current owners, then all previous owners are responsible.

2.3.2.2. Value of Reserves Relative to Decommissioning Liability

Decommissioning liability can create a large risk for the buyer when the abandonment costs exceed the value of reserves. Marginal leases that contain a large quantity of (idle) infrastructure can be particularly troublesome, since for a producing lease to be sold, a rational buyer would purchase the lease only if the present value of production (relative to their discount rate and assumption set on prices, operating costs, exploration potential, etc.) exceeds the expected cost of abandonment. The present value of (future) production and the expected decommissioning liability on a lease are uncertain quantities, depending upon reservoir characteristics, investment patterns, hydrocarbon prices, service markets, and other factors.

2.3.2.3. Decommissioning Cost Relative to Bonding Level

Let $E(C)$ denote the expected cost of decommissioning and B the bonding specification on a lease. If $B > E(C)$, then regardless of the ownership structure, financial capacity, or production level relative to decommissioning liability, there would be no financial risk to the government, since the level of bonding would be sufficient to complete the operation if the property owner went bankrupt. It is only in the case when $B < E(C)$ that the government is exposed to financial risk. The magnitude of B is set by the government and is used as a mitigation tool to manage the decommissioning exposure.

2.4. Bonding Formula Development

A supplemental bonding formula should reflect the objectives and requirements of the MMS. Here we offer a list of objectives that we believe a supplemental bonding formula should satisfy. A supplemental bonding formula should:

1) Reflect the financial obligations associated with decommissioning operations over a specific time horizon.
2) Reduce, not eliminate, government exposure to potential decommissioning liability.
3) Be risk adjusted to account for the inherent uncertainty in operations and cost estimation, and designed to ensure that government exposure is maintained at acceptable levels.
4) Maintain bond levels so that the risk adjustment is proportional to the consequence.
5) Be easy to understand, implement, and interpret; formulated in a clearly-defined and transparent framework, with well-defined assumptions.
6) Be based on a representative set of data reflecting standard industry cost estimation techniques.
7) Be reviewed on a regular basis to assess market conditions and related factors to determine if formula adjustments are warranted.

2.4.1. Bonding Requirements Need to Balance Multiple Objectives and Tradeoffs

A bonding formula is meant to provide financial assurance to the government that the owners of a lease will be able to return the property to its pre-exploration condition upon cessation of production. Bonds are aimed at reducing – not eliminating – the risk of noncompliance, and so the appropriate level of risk that the government should hold is a matter of discourse and consensus.

The level of bonding to meet decommissioning obligations is usually intended to represent the level of commitment by the operator under the assumption of current prices, costs, and technology. Bonding formulas require special consideration, however, since they need to account for a high level of uncertainty in operations and cost estimation, while reasonably reflecting market conditions expected to hold over the near-term future. There is also the issue of whether a bonding formula should account for the cost the government would incur in performing decommissioning – as opposed to reflecting operator cost – since the government would likely incur greater cost under normal conditions, and possibly, significantly greater cost in unusual circumstances.[14]

What is the proper balance between the government's risk exposure and an operator's bonding requirements? How much decommissioning exposure should the government be expected to hold? Since supplementary bonding applies to all leases where at least one owner does not satisfy a specific financial threshold, any formula that sets bonding commitments at a high level would entail an incremental cost to operators, potentially discouraging or preventing investment among small companies, while placing additional economic burden on development and property transactions. On the other hand, bonding levels that are set at average cost do not adequately account for the possibility of cost falling above posted levels, essentially requiring that a portion of the risk be held by the government. If an operator is unable to perform their decommissioning obligations, for example, and the government was responsible to complete decommissioning activities, a host of troublesome litigation could potentially arise[15] in such a situation.

2.4.2. All Bonding Formula Have Limitations and Constraints

The adequacy of a bonding formula is based on our ability to estimate decommissioning cost today and forecasting cost for the time period in the future in which the formula is to be valid. All decommissioning cost estimates are uncertain because project uncertainties and structural variations cannot be adequately captured in a formula using a limited number of variables. Further, even if the precise cost of an operation could be established in advance, the future cost of that operation will be uncertain because of the nature of market conditions, weather, and the impact of other unpredictable events.

In developing a bonding formula, we are constrained by the sample set in which empirical relations are derived along with the number and type of factors available for assessment.

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[14] For example, if one or more small companies hold a large number of marginal properties that are destroyed in a hurricane, it is possible that the companies will default on their lease obligation, and the cost of decommissioning will be significantly higher than average cost.

[15] For example, where would the funds to successfully complete abandonment come from? If decommissioning was not performed adequately, would the government be held liable? Can the government permit a project for which it is the title holder? These questions, while intriguing, lie beyond the scope of this report.

Decommissioning operations are performed by a number of different project management and service firms in the GOM, for operators that hold different expectations, requirements, and planning levels. Data collection is difficult because of the proprietary nature of cost statistics, and is usually representative of specific sectors of the industry. It is desirable to employ a broad cross-section of industry players in data collection, but in reality, obtaining such data is extremely challenging. Because the MMS will only have access to (standard) structure characteristics and specifications – such as number of wells, structure type, and water depth – it is not possible to use potentially better descriptors such as deck weight, jacket weight, etc. in developing a more accurate formula (since these attributes will not always be available to the MMS).

2.4.3. Representative Cost Data Is Required to Establish Bonding Levels

Cost data in general, and decommissioning cost in particular, is difficult to collect over wide sectors of the industry. The proprietary nature of cost data greatly increases the effort required and success of data collection. Operators do not typically provide cost data for sector studies, and despite repeated attempts to illicit participation, it was necessary to consult project management firms and other service providers to supplement the collected data. This will create bias in sample selection since the sampling is no longer random. Observations that are most accessible (small- to mid-size independents) is not a "representative" data set, nor can be construed as a random sample, and additional computations are therefore required to correct for this feature of the data. We will need to balance sample sets from different operator classes to obtain a representative sampling.

2.4.4. Several Choices Exist When Establishing Baseline Cost

Bonding levels can be determined from historical cost, current cost, or expected future cost, with or without risk-adjustment and inflation multipliers, and with or without the inclusion of exceptional events that may have occurred over the time horizon of the data collection (such as hurricanes). The decision to apply one category type or descriptor variable instead of another is a matter of choice, or may be dictated by data availability, application issues, or a specific agency request.

Historical cost is computed over a period of time, and because project costs are taken as an average, the cost statistics include annual changes and the occurrence of any exceptional events reported within the time period. For a bonding formula to hold over a future time period, from current time T to future time $T+p$, $[T, T+p]$, we suggest collecting cost data from a comparable previous time period, from $T-p$ to T, $[T-p, T]$. This procedure recognizes the variability in prices and costs that are expected in the future, equating those to that which have occurred in the past. A restricted time window will minimize the impact of technical improvements over the time period, but will not account for the occurrence of exceptional[16] events or price escalation in the market rates of vessels and equipment.

[16] We can consider exceptional events as part of the normal operating environment and include hurricane-destroyed structure data in our cost assessment. Conversely, we could also argue that such exceptional events should be excluded from analysis, because they occur infrequently and typically affect a small percentage of assets, and are better represented through the application of risk-adjustment factors. In either case, we need to be cognizant of the manner in which data is collected, processed, and presented.

Current cost is estimated based on projects and market rates at a specific point in time, and because there is no time averaging or normalizing process, is subject to the variability of the sample when the estimation is performed.

To estimate expected future cost a model will need to be developed. One of the simplest models to employ is to apply average historical cost as the baseline, risk-adjust, and then adjust for expected inflationary effects over the time period of interest. If historical cost data are believed to be a reliable and reasonably robust method to estimate future cost, then this method will be sufficient. Since decommissioning operations are not subject to significant technological progress, the main driver to cost volatility is market conditions at the time of the event. If historic data is sufficiently “representative” and project requirements are “normal,” then historic cost is likely to serve as an adequate guide of expected cost if future market conditions and project requirements are also “normal” during this time.

2.4.5. A Risk-Adjusted Bonding Formula Will Reduce Government Exposure

The cost of decommissioning is influenced by factors that are largely unknown or unpredictable, and so a number of assumptions are required to set bonding levels across each of the main stages of the operation. Some stages are more uncertain and more important than others. Plug and abandon and structure removal activities are the most variable and represent the largest contributor to total cost, while site clearance and verification operations tend to be less variable and a much smaller percentage of cost. Preparatory activities and pipeline abandonment are important cost components which are usually aggregated in structure removal estimates. One motivation for a bonding formula to be risk-adjusted is to account for the uncertainty associated with operations and structural differences that are known to impact cost.

We believe that the government should adopt a low-to-moderate risk-averse position toward bonding requirements. Risk aversion will help ensure that the majority of decommissioning cost in normal cases will be adequately covered through supplemental bonds, and for problem wells and difficult cases, a larger part of the cost will be covered than if bonding requirements were set at average levels. Effective mechanisms currently exist that provide a reasonable degree of protection for the government upon company default that makes the level of risk, under normal conditions, moderate and manageable. The government cannot eliminate risk nor account for the exceptional event (hurricane destruction) without imposing extremely burdensome requirements on operators. Any risk-adjustment should reflect such considerations.

2.4.6. Bonding Mechanisms Should Be Clearly Defined with Transparent Assumptions

It is desirable that a bonding formula be easy to understand, implement, and interpret, because it is a frequent point of reference by operators and the government, and is used on a regular basis. A well-defined set of assumptions is required, and analysis should be based on reliable and balanced cost data with procedures that are transparent, reflecting best practice.

A well-defined bonding formula will specify the time-period in which the formula is to be valid, is presented at an appropriate level of decomposition, applies empirical data to develop average baseline estimates, and adjusts cost to the future using an inflationary index, where necessary. Risk adjustment factors should be explicit and based upon historical cost data.

2.4.7. Standard Deviation Multiples Provide a Simple Risk-Adjustment Mechanism

The actual cost of decommissioning will always deviate from bonding levels determined by formula, but a well-specified formula will ensure that the magnitude and sign of the deviation is consistent with regulatory objectives.

It is suggested that the average cost of decommissioning per category be adjusted by a multiple of its standard deviation and inflation-adjusted for a specific future horizon. In this way, we do not attempt to forecast site specific conditions, future market conditions, the occurrence of exogenous events, or other conditions that are not predictable. Rather, recognizing the need of a bonding formula to set risk at a level commensurate with consequence, we propose historic average cost data per category as the baseline bonding level adjusted with appropriate risk and inflation factors.

Under normality assumptions of the cost data, each standard deviation multiple selected will cover the cost of projects that fall outside the range of the average. By selecting one or two standard deviation multiples, we capture most of the upside uncertainty expected to occur within each categorization, which is consistent with a low-to-moderate risk aversion level and the ability of the model to encompass regulatory requirements.

2.4.8. A GOM Bonding Formula Needs to Be Algorithmic and Class Specific

Offshore structures in federal waters currently exist off the coast of Alaska, California, and the GOM. In the Alaska, Pacific Coast, and deepwater[17] GOM regions, only a few dozen structures currently exist, and so detailed engineering estimates can be performed at a structure level to assess liability and supplemental bonding requirements (Gebauer et al., 2004). For the deepwater regions, structures are owned by financially secure operators, and so the need for supplemental bonding is currently limited. In the shallow water region of the GOM, however, engineering estimates to assess decommissioning liability are not practical[18] or viable because of the large number and diversity of wellbores and structures. A general (generic) bonding formula is desired because the number of structures exceeds the ability to perform individual estimates.

Because of the variety of structures in the shallow waters of the GOM, an aggregate assessment needs to be performed, with cost normalized according to structure complexity, water depth, and other factors, as appropriate, across each stage of the operation. Cost estimates are intended as first-order approximations of abandonment expenses, based on site characteristics described by one or two primary variables and meant to create categories that are reasonably "homogenous" with respect to structure characteristics. Inclusion of factors such as wellbore complexity, number of pilings, deck and jacket weight, and related variables would enhance the quality of the cost estimation, but are not always readily available, so such data cannot be employed.

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[17] Defined as water depths greater than 1,000 ft.

[18] Site visits to perform cost estimation in the shallow water GOM is not practical. Engineers would need to access all facilities, and unless they used identical guidelines and checklists, would fail to achieve uniform cost estimates. The time and effort to perform such an assessment would also be significant. Further, costs would still only be based on visible or known conditions.

2.4.9. A Bonding Formula Should Remain Valid for a Specified Period of Time

A bonding formula is intended to serve all new and existing wellbores and structures over a given time period, p, from the current time T through time $T + p$, $[T, T + p]$. Decommissioning cost change over time, but a bonding formula needs to be sufficiently robust to remain valid for a period of time. It is possible to index a bonding formula to changes in the dayrates of vessels and other relevant factors, but the benefits derived from a time-indexed mechanism and the administrative expense of a dynamic bonding formula – from both the government and operator perspective – far outweighs the benefits that such a formula would provide. A bonding formula that is constructed for a fixed duration – say a 5-year period – will reduce compliance cost and encourage a review of the decommissioning market on a periodic basis. A bonding level review may also be prompted with any significant changes in the model assumptions, market structure, or regulatory changes.

2.5. Additional Issues

2.5.1. Bonding Formulas Cannot Replace Company-Level Decommissioning Assessments

A bonding formula does not, nor cannot, serve as an engineering assessment of a company's decommissioning liability. An operator wishing to assess their aggregate decommissioning liability will need to perform a detailed, site-specific, structure-by-structure review using experienced personnel and adequate consideration regarding removal options and downhole conditions.

A bonding formula can only capture average characteristics under expected conditions. The formula cannot identify the specific requirements of decommissioning, what the service market will be at the time of the operation, what problems – if any – will arise in the activity, what options the operator has to reduce removal cost, etc. Fortunately, a high level of precision is not required in setting bonding levels, because a bonding formula only needs to account for "average" conditions and "expected" outcomes for a typical offshore structure under "normal" future conditions.

2.5.2. New Data Collection Efforts Would Benefit Future Assessments

Reliable and comprehensive cost data are neither accessible nor widely available in the offshore industry, and so new data collection efforts are suggested to improve future bonding formulas and to ensure that levels remain properly calibrated. To maintain a bonding formula based on the most up-to-date and reliable cost data, it is suggested that all future decommissioning operations report cost to the MMS on a proprietary basis. The reporting requirements would be modest – involving perhaps 15 data entries per decommissioned structure (see Appendix G for a sample report) – and take 5-10 hours to complete. The information could be used to calibrate supplemental bonding requirements during the next review period. The information will greatly enhance the government's ability to determine decommissioning expenditures, which will, ultimately, reduce uncertainty in future bonding reviews and enhance system efficiency.

2.5.3. Government Decommissioning Projects Would Likely Fall Above Average Costs

A private company, depending on its size, experience, and strategic opportunities, may be able to realize significant operational savings and discounts for its decommissioning requirements – through multi-well contracts, economies of scale, scheduling advantages, removal options, vessel selection, reuse opportunities, strategic alliances, etc. – but this would not be the scenario facing the U.S. government. If the MMS had to assume responsibility for decommissioning one or more offshore structures, it may need to secure the services of a project management firm specializing in decommissioning to manage the logistics and permitting process. Potential conflicts of interest may arise. Scale economies would not be realized, but it is conceivable that alternative removal methods (i.e., reefing) would be available to reduce costs. If safety or environmental concerns (e.g., leaking wells) warranted immediate action, activities would need to be performed on an emergency basis at additional cost. Insurance may be required to avoid liability issues. In the event that the U.S. government needed to assume abandonment obligations, we would expect the cost to be "more similar" to a major or large independent performing the operation than a small or mid-size independent.

2.5.4. The Government Should Not Be Exposed to Excessive Decommissioning Liability

As discussed previously, a risk-based regulatory approach to bonding mechanisms recognizes the uncertainties inherent in cost estimation and decommissioning activities. We do not attempt to capture the risk associated with an individual operator or job since these efforts are not tractable. We recognize that the probability of decommissioning liability falling to the government is low, but the magnitude of exposure is potentially large. A risk-based approach is intended to balance the interests of the government to prevent future liability due to inadequate bonding levels, while not requiring an excessive financial burden on owners.

2.5.5. Bonding Level Petitions Should Be Risk-Adjusted With Clearly Stated Assumptions

Historically, the MMS has allowed operators to petition the value of their supplemental bonding requirements if large discrepancies arise between an operator's estimates of their decommissioning cost and the government's application of the formula values. The MMS grants expert third-party decommissioning cost estimates to be provided as evidence in their assessment on a case-by-case basis. We believe this is a good practice to continue, since it recognizes the inherent limitations of any formula to gauge decommissioning cost at a company level. All assumptions regarding decommissioning cost estimation should be fully documented to ensure consistency with the updated formula and regulatory guidelines. The MMS will need to decide if it will allow discounting in the petitioned values so that an appropriate comparison can be made. Uncertainty bounds are suggested to assess similar risk-adjusted values.

2.5.6. Specialized Bonding Formulas Are Not Suggested

Specialized bonding formulas could be developed for structures in high-risk areas of the GOM, such as mudslide regions, as well as structures fabricated according to old design standards which do not satisfy API guidelines for deck heights (air gap requirements). Deepwater fixed structures would also warrant special consideration. In practice, the benefits of applying specialized bonding formulas do not warrant the additional cost involved in development and administration, and such an approach is not suggested. As discussed previously, since there are only a few dozen deepwater structures, individual assessments for these structures is feasible, but because the uncertainty involved with their disposition remains high, cost estimates for these class of structures may be in considerable error.

2.6. Conclusions

The objective of the MMS bonding program is to ensure that all entities performing activities under the jurisdiction of the MMS provide or demonstrate adequate financial resources to protect the U.S. government from incurring financial loss. Bonds represent hybrids of market mechanisms and control regulations which require companies to internalize ex-post environmental liabilities within their cash flow accounting, making costs explicit to shareholders. Each lease in the GOM is reviewed to ensure that at least one working interest owner has adequate financial coverage to provide for the performance of all lease obligations when the designated operator and/or the lessees cannot fulfill their requirements. Financial securities are necessary to ensure that owners fully comply with regulatory and lease requirements that include rent, royalties, environmental damage, cleanup and restoration activities, abandonment and site clearance, and other lease obligations.

3. SUPPLEMENTAL BONDING RISK-ADJUSTED TABLEAU

3.1. Introduction

For all leases in the GOM in which estimated lease liability exceeds a specified financial commitment for all owners, a supplemental bond must be posted. The value of the bond is determined by counting the number of unplugged wells and structures on the lease and then applying the formula shown in Table C.1, which we refer to as the supplemental bonding (legacy) formula.

In the current MMS supplemental bonding formula, plug and abandonment unit cost is per borehole, removal cost is per structure, and site clearance and verification cost is per leasehold. Total lease liability is computed by multiplying the number of wells and structures on a lease by the appropriate unit cost elements and then summing. The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate. For example, an operator can petition the level of supplemental bonding required by providing a detailed engineering review of the estimated cost by a third-party. For water depths greater than 300 ft, specialized assessments are required.

The purpose of this chapter is to provide a recommended update to the MMS formula using a risk-adjusted mechanism. The procedures, assumptions, and updated risk-adjusted bonding levels are presented across the three main stages of decommissioning. We begin by discussing user preferences and the restrictions imposed by data availability. Assumptions specific to each stage of decommissioning and a summary of cost statistics are discussed separately in sections covering plugging and abandonment, structure removal, and site clearance and verification. Risk-adjusted bonding levels are presented in four tables and two examples demonstrate their application.

3.2. Model Development

3.2.1. Baseline Level

The baseline bonding level for each of the main stages of decommissioning is set at the average historical cost to perform the activity unless an inflationary trend is identified in the data, in which case data for the last year would be employed. It is recommended that bonding levels that are to apply for a *p*-year future time horizon be computed from data collected from no longer than a *p*-year historical time frame, and vice versa. For example, if cost data is only available for a 5-year period, then a bonding formula should be used for no longer than a 5-year future horizon.

3.2.2. Formula Duration

Bonding requirements are set at a specific time and apply to current decommissioning operations as well as future activity. This creates an obvious dilemma when setting bonding levels, since costs may inflate and levels set at the current time may not represent future expenditures. For formula durations that extend across a limited time horizon, say no longer than 3-5 years, this problem is expected to be minimal. To reduce the level of ambiguity and to encourage a regular bonding review cycle, it is recommended that the duration in which the formula is to apply should be specified explicitly.

3.2.3. Inflation Factor

Cost indices are available for different segments of the oil and gas industry, but offshore decommissioning is a highly specialized sector which is not tracked by the U.S. Census Bureau or other agencies. There are also no good proxy measures for cost inflation that we believe is representative of the sector. Activities that depend on support and construction vessels may require an inflationary adjustment, due to changes in labor rates, fuel, demand requirements, etc. or may be relatively immune to inflationary pressures. Supply and demand conditions in the GOM determine market rates, and because the uncertainty and magnitude in market rates typically dominates inflation uncertainty, empirical data may not provide clear trends on the occurrence/absence of inflation effects. To complicate matters, inflationary effects are also sample-dependent, and unless a large and diverse sample is obtained, may not be representative of general GOM conditions. Inflationary adjustments need to be applied with caution.

3.2.4. Inflation Adjustment Period

A bonding formula is specialized by the user for the period p, starting from year T, and extending through the time horizon $T + p$, $[T, T + p]$. The value of p is user-defined. If the expected cost to perform decommissioning activity i in year j is denoted by $C_i\ (j)$, how do we set the bonding level B_i over the time interval $[T, T + p]$ if inflationary factors are to be incorporated in the formula?

If B_i is set at the level $C_i\ (T)$ and inflationary factors are significant, operators who decommission in the future at time $T + 1, \ldots, T + p$ will have a bond that does not adequately cover the expected cost of the activity, while if B_i is set at the inflation-adjusted level expected to hold through the end of the period, $C_i\ (T + p)$, then operators who decommission at any time $t < T + p$ will be required to acquire a bond at higher than expected cost. With the value of p user-defined, it is suggested that cost be calibrated to the midpoint of the horizon in which the formula is to apply at time $T + [p/2]$.

3.2.5. Representative Cost

In a perfect world, decommissioning cost from all operations in the GOM would be reported at the conclusion of every project under a common cost accounting system. Project characteristics would be complete, and detailed descriptions of the wells, structures, contract terms, weather events, etc. would be recorded and available for analysis. In this perfect world, average cost would be easily computed, and because all operations would be reported, no uncertainty would arise regarding the nature of the assessment and if it was "representative" of the industry. The impact of category selection and other user-defined variables would be clear and readily analyzed.

In the real world, acquiring cost data that is representative of the industry is a much more difficult task, due to confidentiality concerns, the lack of industry interest, the proprietary nature of the activity, and the large time and resource commitments required. Data collection is often a "hit-or-miss" endeavor and depends on the goodwill of industry, the patience and fortitude of the analyst, ample optimism, and of course, luck. In the real world, data sets are neither complete nor representative, and care must be taken to ensure that the data that is collected is analyzed with due regard to the specific characteristics of the operations. In the real world, significant bias can result from sample selection problems or loose analysis. Cost statistics are directly tied to the nature of the sample set and available project descriptors, and cannot be considered "representative" of the industry by default. In almost all cases, additional processing of the data is necessary.

3.2.6. Data Balancing

Like many offshore activities, cost data for decommissioning operations is relatively sparse and often focused on independent operators. Majors usually do not divulge the cost of their operations in the public domain. For cost to be representative of all operators in the GOM – independents and majors – we will need to "balance" the data so that both groups are adequately represented. We recommend employing an equal-weighted averaging scheme, where projects are first averaged according to operator type, and then class averages are performed through an equal-weighting. This is a user-preference and the equal-weight scheme is employed based upon the belief that if the federal government was required to perform decommissioning activities in the GOM (for any company, independent or major), the cost of services would more likely be similar to what a major would experience than an independent. Rather than use only the cost of operations of majors, and because of the lack of good data for majors, the equal-weight class average attempts to balance the representative nature of operations with the availability of reliable data.

Formally, if μ_{IND}, μ_{MAJ} represent sample average cost for independents and majors, respectively, then an equal-weighted category average cost C is computed as

$$C = \frac{\mu_{IND} + \mu_{MAJ}}{2} .$$

Standard deviation of the sample data are computed and applied as a proxy for uncertainty. If σ_{IND}, σ_{MAJ} represent the sample standard deviation for independents and majors, respectively, then an equal-weighted category standard deviation SD is computed as

$$SD = \frac{\sigma_{IND} + \sigma_{MAJ}}{2} .$$

The values of C and SD are used in the risk adjusted bonding levels that follows.

3.2.7. Data Uncertainty and Risk Tolerance

Bonding levels are risk-adjusted to reflect the uncertainty associated with operational and market activity, cost estimation, and the risk tolerance level of the federal government. None of these factors is expected to dominate every situation, and so risk adjustment is viewed as a means to account for the combination of all data uncertainty and risk tolerance variation. If the government had to assume responsibility for decommissioning one or more structures, it would likely need to secure the services of a project management firm to manage the logistics and permitting process, scale economies would not likely be realized, and safety and environmental concerns would likely increase expenditures above average cost.

3.2.8. Risk Adjustment

Bonding levels are adjusted upward from the baseline (average) cost by 1, 2 and 3 standard deviation multiples.[19] There is a trade-off in the selection of the risk adjustment, since any increase above average cost will impose a greater financial burden[20] on operators, while holding bonding levels at average cost will transfer a greater portion of decommissioning exposure to the government.

For each stage of decommissioning, four bonding levels are presented:

- Average Cost: *C* (high risk)
- Risk-Adjusted Cost I: $C + 1*SD$ (moderate risk)
- Risk-Adjusted Cost II: $C + 2*SD$ (low risk)
- Risk-Adjusted Cost III: $C + 3*SD$ (very low risk)

Qualitative risk indicators "high", "moderate", "low", and "very low" are assigned to each category based on the frequency in which actual costs are likely to exceed the average costs under normal conditions. The use of the indicators is subjective and meant to be interpreted in a relative sense. It is difficult to establish in a quantitative manner the correspondence between risk and decommissioning exposure, but by incorporating one or more standard deviation terms, the government is less likely to be exposed to liability arising from inadequate bonding levels. Average cost represents the base case and is considered a high risk category. By adding one or two standard deviation multiples to the base case, the risk-adjusted cost presents a lower risk that decommissioning will exceed[21] posted bonds.

3.3. General Methodology

The methodology adopted is to recognize the uncertainty that exists in cost estimation and to incorporate a portion of this uncertainty explicitly within the bonding formula. The approach in setting bonding levels follows the same steps for each stage of decommissioning:

1) Collect, review, and analyze cost data from a sample of GOM operations over the past decade, with particular emphasis on the most recent 5 years.
2) Filter, process, and disaggregate data according to a consistent level of categorization, normalizing with respect to structure type, water depth, operator type, and related factors.
3) Compute average cost and standard deviation for each sample based on a water depth and structure type categorization.
4) Use standard deviation as a risk adjustment factor according to perceived levels of risk and the tradeoffs involved with protecting against small probability events.

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[19] Fractional multiples could also be used.

[20] The cost to the operator is not the only premium, since less capital would be available for use in E&P activities that might otherwise be used.

[21] In some circumstances, even risk-adjusted costs may not be adequate to perform decommissioning activities.

5) Balance the sample data to obtain average cost and standard deviation representive of GOM operations.

   a) Let μ_{IND}, μ_{MAJ} represent the average sample cost for independents and majors, respectively, and $\sigma_{IND}, \sigma_{MAJ}$ the standard deviation.

   b) Compute the average category cost and standard deviation based on the average sample data:

$$C = \frac{\mu_{IND} + \mu_{MAJ}}{2}$$

$$SD = \frac{\sigma_{IND} + \sigma_{MAJ}}{2}$$

   c) Tabulate the risk-adjusted cost categories:

      Average Cost = C

      Risk-Adjusted Cost I = C + 1*SD

      Risk-Adjusted Cost II = C + 2*SD

      Risk-Adjusted Cost III = C + 3*SD

6) Determine the inflationary factors that apply, if any, across each stage of decommissioning using data trends, professional judgment, and expert opinion.

7) Compute inflation-adjusted cost normalized across the time period in which the bonding formula is intended to apply.

3.4. Plugging and Abandonment Bonding Tableau

3.4.1. Model Assumptions

- Time period of the formula is user-defined.
- All wellbores on a lease are considered except permanently plugged and abandoned wells. Wells include producing (active), idle (inactive, shut-in, temporarily abandoned), and service (disposal, injection) wells.
- No distinction between wells are made based on age, production type (oil, gas, condensate), water depth, completion type (single or multiple), trajectory (vertical, deviated, horizontal), number of sidetracks, or other complexity measures.
- Costs are determined based on the application of rig and rigless techniques, platform and liftboat jobs, dayrate and turnkey contracts.

- Scale economies apply in the operation; e.g., wells may be plugged individually or on a multi-well contract.
- Only "normal" operations are considered. P&A work for hurricane destroyed structures/wells are not considered.
- Only surface systems or wells with a surface tree in less than 300 ft water depth are considered. Hybrid wells and wet trees (subsea wells)[22] in water depth greater than 300 ft require a separate assessment.
- P&A technology will remain essentially unchanged over the time horizon under consideration, and no significant changes in the regulatory framework will occur during this time.
- P&A project costs by independents and majors are computed as separate sample averages, and an equal-weighted class average is computed.
- A 10% cost inflation rate per year is applied.

3.4.2. P&A Summary Cost

P&A average cost and standard deviation data is summarized for independents and majors in Tables C.2 and C.3. The data for independents is analyzed in further detail in Chapter 4 and in (Kaiser and Dodson, 2008). Cost data for majors was provided by MMS.

There is a significant difference in the average P&A cost between independents and majors. Based on 1,156 wells plugged from 2002-2007, the average P&A cost for independents is $134,000. In 2007, the average P&A cost was $178,000 with a standard deviation of $51,000. For majors, based on 115 wells plugged from 2005-2007, the average P&A cost is $1.1 million with a standard deviation of $956,000.

An equal-weighted class average and standard deviation for the two sample sets yields:

$$C = \frac{\$178{,}000 + \$1{,}100{,}000}{2} = \$639{,}000$$

$$SD = \frac{\$51{,}000 + \$956{,}000}{2} = \$504{,}000 .$$

[22] Subsea wellheads require specialized equipment for service, including riser handling systems, subsea service equipment, ROV services, and diving facilities, which substantially increase intervention activities and the cost of abandonment.

3.4.3. P&A Bonding Tableau

The P&A bonding tableau in Table C.4 provides an inflation-adjusted class average cost based upon a user-defined time frame and risk-adjustment selection.

To apply Table C.4:

Step 1: Define the time horizon in which the bonding formula will be valid. Specify the last year of the desired time horizon.

Step 2: Go to column two and read off the corresponding value of *p*.

Step 3: Now go to row [*p*/2]; round up for odd *p*.

Step 4: Select column according to desired objectives, levels of uncertainty associated with estimation, and level of risk adjustment, and read off the value of the bonding levels.

3.5. Structure Removal Bonding Tableau

3.5.1. Model Assumptions

- Time period of the formula applies for 2008-2013.
- Conventional technology for all operations are employed, and all possible disposition options are permitted; i.e., platforms may be completely removed with all materials transported to shore for recycling or disposal, or the structure may participate in a reefing program.
- Removal technology will remain essentially unchanged over the time horizon under consideration, and no significant changes in the regulatory framework will occur during this time.
- The impact of environmental mitigation cost; the cost to retain an agent; engineering, planning, permitting, and regulatory compliance; weather and general contingency factors; and “abnormal” market conditions that may occur in the future are not part of the assessment.
- Only “normal” operations are considered. Structures destroyed by man-made or natural catastrophe are not part of the assessment.
- No scale economies occur in operations; e.g., structures will not be grouped in a multi-structure removal package.
- Only fixed structures in less than 300 ft water depth in the Gulf of Mexico are considered. Structures in water depth greater than 300 ft or residing outside of the GOM require a separate assessment.
- Caissons and well protectors as defined by the MMS are considered similar structures for the purpose of removal and are grouped within the same category. Fixed platforms comprise a separate category.

- Removal cost for caissons and well protectors include pipeline abandonment operations. Removal cost for fixed platforms includes structure preparation activity and pipeline abandonment operations.
- Removal costs by independents and majors are computed as separate sample averages, and an equal-weighted class average is computed.
- Cost data is not inflation adjusted.

3.5.2. Removal Summary Cost

Removal cost and standard deviation data by structure type and water depth is summarized for independents in Table C.5 and majors in Table C.7. In Table C.6, a risk-adjusted removal cost tableau is computed from the average and standard deviation data presented in Table C.5. In Table C.8, a risk-adjusted removal cost tableau for majors is computed from the sample average and standard deviation data presented in Table C.7. The data for independents is analyzed in detail in Chapter 5 and in (Kaiser et al., 2008). Data for majors was provided by MMS. Due to the variation in average cost and standard deviation between independents and majors, the bonding levels escalate at different rates.

3.5.3. Removal Bonding Tableau

The risk-adjusted removal bonding tableau is computed as the equal weight average of the independent operator sample average and major sample average elements depicted in Table C.6 and Table C.8.

3.6. Site Clearance and Verification Bonding Levels

3.6.1. Model Assumptions

- Tine period of the formula applies for 2008-2013.
- SC&V will be performed using net trawling under dayrate contracts.
- Water depth is limited to 300 ft or less.
- Structural units are grouped and counted in terms of caissons and all other jacketed structures (well protectors and fixed platforms) to match the clearance area requirements defining by the MMS.
- Cost data is not inflation adjusted.

3.6.2. SC&V Bonding Tableau

Cost statistics for trawling operations based on data collected for independents and majors are presented in Table C.10 and are discussed in greater detail in Chapter 6 and in (Kaiser and Martin, 2009). The small contribution of SC&V to total cost makes this category significantly less important than P&A and removal operations.

3.7. Risk-Adjusted Supplemental Bonding Tableau

The MMS supplemental bonding legacy formula was updated using a risk-adjusted mechanism across each of the main stages of decommissioning. The average (no risk-adjustment) cost of decommissioning is presented in Table C.11. Three risk-adjusted levels are presented in Tables C.12-C.14 using standard deviation as a proxy for the risk-adjustment factor. The updated formula maintains the same structure as the legacy formula, but is only directly comparable across the P&A category, where we observe that average P&A cost since the early 1990s have increased roughly seven-fold. In the structure removal category, costs have increased 2-4 times greater than the legacy formula. Site clearance and verification cost are smaller in the new formula and are structure specific. In the legacy formula, removal cost is not specified with respect to structure type, and SC&V does not refer to the number or type of structure on the lease. In the new formula, structure type is specified across the removal and SC&V categories.

3.8. Illustrative Examples

3.8.1. Example 1

On lease A in 75 ft water depth, there exists an inventory of 5 producing wells, 18 idle wells and 3 service wells; and 2 caissons, 1 well protector, and 2 fixed platforms, as defined by the MMS. The supplemental bonding required on the lease if none of the working interest owners meet the minimum financial requirements of the MMS are determined as follows. First, we enumerate the number of wells and structure count by type, and record the water depth of each entity:

- Total well count: 26
- Structure count by type: CAIS = 2, WP = 1, FP = 2
- Water depth: 75 ft

Then we apply Tables C.11-C.14 to determine bonding levels. We illustrate the calculation for the average cost case. Using Table C.11 yields

- P&A cost = 26 * $773,000 = $20.1 million;
- REM cost = 3 * $1,260,000 + 2 * $1,527,000 = $6.83 million;
- SC&V cost = 2 * $16,000 + 3 * $43,000 = $161,000;

or a total supplemental bond of $28.39 million for the lease. The risk-adjusted bonding levels are computed similarly from Tables C.12-C.14 and are shown in Table C.15.

3.8.2. Example 2

On lease B in 170 ft water depth, none of the record title holders of a producing lease satisfy the specified financial capacity of the MMS. Assets on the lease include 1 producing platform with 3 active wells and 7 inactive wells. Idle infrastructure on the lease includes 3 caissons (each containing 2 wells) and 1 fixed platform containing 15 wells. The supplemental bonding requirement of the lease under the moderate risk category (Table C.12) is computed as follows.

- Total well count: 31
- Structure count by type: CAIS = 3, WP = 0, FP = 2
- Water depth: 170 ft

From Table C.12,

- P&A cost = 31 * $1,383,000 = $42.87 million;
- REM cost = 3 * $2,750,000 + 2 * $3,503,000 = $15.26 million;
- SC&V cost = 3 * $26,000 + 2 * $67,000 = $212,000;

which yields a total supplemental bond requirement of $58.34 million. A summary of the bonding requirements associated with the other risk categories is presented in Table C.16.

4. COST OF PLUG AND ABANDONMENT IN THE GULF OF MEXICO

4.1. Introduction

Wells are drilled into geologic formations to explore, delineate, and produce hydrocarbon reserves, and at the end of their useful life, are permanently abandoned in a process known as plugging and abandonment (P&A). The purpose of P&A is to prevent the migration of fluids from the wellbore and establish a permanent barrier to the existing geologic formation. The goal of P&A is to ensure downhole hydrocarbon formations are isolated, freshwater aquifers are protected, and migration of formation fluids from the wellbore or to the seafloor are prevented.

The operator designs a P&A operation based on the reservoir and wellbore conditions and applies for regulatory approval. In most states, rules have evolved over many years with standards based on experience and conformance with industry guidelines (Bull, 1993; Calvert and Smith, 1994; Smith, 1993). Different government bodies regulate wellbore abandonment and the regulatory body with primary responsibility is dependent on the location of the well. Onshore and in state waters the county, city, or state government is responsible for oversight, whereas in the federal OCS, the MMS is the lead agency, with participation by the U.S. Corps of Engineers, U.S. Coast Guard, and National Marine Fisheries Services.

Wells in the OCS must be permanently plugged and abandoned within 1 year after the lease terminates, which often occurs after the last well on the lease ceases production. The MMS may require that a well be permanently plugged before lease production ceases if it poses a hazard to safety or the environment, or if it is not useful for lease operations and is not capable of production in paying quantities (Federal Register, 2002). Oil and gas wells may also be shut-in or temporarily abandoned throughout their life cycle because they are not producing hydrocarbons in paying quantities or for mechanical/technical reasons. The MMS provides regulations for placing a well in temporarily abandoned or shut-in status.

Plugging and abandonment operations are considered one of the more variable portions of decommissioning because the operation is influenced by a large number of variables and events, and tend to depend on factors that cannot be modeled accurately. Some of the factors that influence the time and cost to plug and abandon a well include the contract type, site location, job specification, water depth, and the occurrence of exogenous events, such as weather and problem wells. Many factors are unobservable and involve elements such as wellbore complexity, job preparation, and contractor experience. Reporting practices of contractors and operators determine what job characteristics are recorded and available for analysis.

The purpose of this chapter is to review historical P&A cost data for trend analysis and estimation applications. The outline of the chapter is as follows. We begin with a classification of nonproducing wells and review the primary stages of the P&A process. Factors that impact P&A operations are then outlined. Descriptive statistics based on 256 job reports collected from a major service producer in the GOM are summarized and discussed. The impact of scale economies and the limitations of the analysis are also described.

4.2. Wellbore Classification

4.2.1. Well Life Cycle

Every well has a unique life cycle in terms of its cost, duration, recovery, and value. Although these characteristics and attributes are specific to an individual wellbore, all wells pass through the same states, beginning with completion and ending with abandonment.

After a well is drilled to target depth, it is evaluated to determine if it should be completed. Formation evaluation is a critical step in exploration since it is the stage in which information about the presence/absence of hydrocarbon bearing reservoirs is acquired. A drill stem test may be used to evaluate the flow rates of hydrocarbons, and integrating the data with logs and other tests, leads to the completion decision. If a sufficient quantity of reserves is expected to exist, with value greater than the cost to complete the well, the well will likely be completed and produced. Over its life, the wellbore may be sidetracked, deepened, plugged back, or worked over one or more times.

Eventually, all wells become inactive because of diminished economic returns or technical problems. When a well stops producing, it may either be shut-in (SI), temporarily abandoned (TA), or permanently abandoned (PA). The MMS provides specific regulations for each state depending on the status of the well.

4.2.2. Shut-in Status

A SI well is a flowing well that has its christmas tree, master valves, wing valves, and subsea safety value closed. A well is usually shut in because of technical or operational problems of a temporary nature (e.g., in the GOM, wells are shut-in if they reside within the expected path of an approaching hurricane). A well can be maintained in a SI state for any length of time as long as proper periodic maintenance procedures are followed. MMS regulations specify that "… completions shut-in for a period of six months shall be equipped with either (1) a pump through type tubing plug; (2) a surface-controlled subsea safety valve, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow" (20 CFR, Ch.II, 250.801 (f)).

4.2.3. Temporarily Abandoned Status

When an exploratory well is under evaluation or when a flowing well on an active lease is no longer economic to produce, the well will often be temporarily abandoned. After the 2005 hurricane season, a large number of wells on destroyed infrastructure were temporarily abandoned as operators assessed field redevelopment strategies. In a TA operation, the wellhead is removed, the producing formation is isolated with plugs, and casing is plugged below the mudline and a corrosion cap is inserted above the mudline (Figure D.1). For TA wells, the operator must provide within one year of the abandonment and at one-year intervals, an annual report describing plans for re-entry to complete or permanently abandon the well (30 CFR, Ch 11, 250.703). Monitoring requirements for TA wells are less than for SI wells. From an economic perspective, the operator weighs the cost of ongoing maintenance activity against the benefits of postponing well abandonment. A number of considerations are involved in the decision, including remaining recoverable reserves, strategic planning, maintenance costs, and workover costs.

4.2.4. Permanently Abandoned Status

At the end of the life of a lease, when lease production ceases, all the wells on the lease must be permanently abandoned. Whereas a well in SI or TA status is considered a temporary, or transitory, stage, a PA well is the terminal state of a wellbore. In a PA operation, former producing horizons are plugged and casing is cut off below the mudline according to regulatory guidelines (Figure D.2). In a PA well there are at least two, and often three, zone isolating plugs. Procedures and verification testing in PA operations are more rigorous than in TA operations.

4.3. Plugging and Abandonment Process

Five stages characterize the P&A process: Planning, Regulatory Approval, Plugging Operation, Wellhead and Casing Removal, and Reporting Requirements.

4.3.1. Planning

Wells that need to be plugged and abandoned begin with a review of the existing wellbore design along with records of past work, well performance, and geologic and reservoir conditions. The quality and extent of the records vary with the age of the well, the number of times the asset exchanged owners, and many other factors. The time lapse between well completion and P&A often results in hardware deterioration and the loss of accurate records. The operator investigates all items related to health and safety issues, as well as regulatory requirements, and designs a P&A program based on the reservoir and wellbore conditions. A comprehensive plan will include contingency responses to difficulties that may occur while plugging the well.

4.3.2. Regulatory Approval

In the federal OCS, the operator is required to submit form MMS-124, "Application for Permit to Modify (APM)," and receive approval for the operation. Form MMS-124 contains information on the reason the well is being plugged, a description of the work requirements, an assessment of the expected environmental impacts of the operation, and the procedures and mitigation measures taken to minimize such impacts (Federal Register, 2002).

Federal regulations are written to have general application to all wells and specify the minimum requirements necessary. The description of the work requirements includes the type and weight of well-control fluid to be employed; properties of mud and cement to be used; perforating and casing cutting plans; plug locations, types, and lengths; plug testing plans; casing removal (including information on explosives, if used); and proposed casing removal depth. Before beginning operations, the MMS District Supervisor is required to be notified at least 48 hours prior to the operation.

4.3.3. Plugging Operation

Each well is unique, and the experience of the operator, planning, and the conditions at the time of the activity will determine the success of the operation.

4.3.3.1. Equipment Requirements

Normal operations require several types of equipment. Standard equipment includes electric wireline/slickline units, hydraulic pumps, cement blenders, circulation tanks, detection equipment, Naturally Occurring Radioactive Material (NORM) meter, handling tools, hoses, sand cutter equipment, chicksans, casing jack, tubing pipe, and hydraulic cranes. Supplies may be expendable (e.g., bridge plug, cement, water, drilling fluid, etc.) or nonexpendable (e.g., drill pipe, special tools, etc.).

4.3.3.2. Equipment Removal

The first step in the P&A process is to remove downhole equipment such as packers, production tubing, gas lift mandrels, and downhole pumps. The operator is required to make a diligent effort to remove all downhole equipment, but because of age and wellbore conditions, this is not always possible. Equipment removal is typically accomplished using a conventional workover or drill rig with the proper rated capacity. Equipment stuck in the wellbore may be left in place if approved by the appropriate agencies.

4.3.3.3. Wellbore Cleanout

The well is cleaned with circulating fluid to remove fill, scale, and other debris covering the perforations. The circulating fluid is required to have a sufficient density to control subsurface pressure and the physical characteristics to remove unwanted material. Back pressure valves may be installed in the well. After the wellhead is removed, the blowout prevention equipment is installed.

4.3.3.4. Cement Plugging

Well plugging procedures usually require a minimum of three cement plugs, but the exact number of plugs varies with the downhole conditions of the wellbore and the number of production zones. The MMS does not require that API class cement be used, but the cement must meet the approval of the District Supervisor. Cement is pumped into the well at the desired location and after several hours (8-12 hr) hardens to form a protective plug. Cement plugs are designed to fill a certain length of casing or open hole to provide a seal against the vertical migration of fluid or gas. Most plugs are 100 to 200 feet in length.

The basic method in plugging a well is to

- Squeeze the producing zone to eliminate the influx of fluid/gas,
- Place a plug near the middle of the wellbore or near a protective pipe shoe, and
- Place a surface plug within 200-300 feet below the mudline.

There are various techniques for setting the plug and a majority of slurry systems are placed through tubing, coiled tubing, drillpipe, or tremie pipe (Smith, 1993). The method used is dependent on wellbore conditions, regulatory requirements, and contractor preference. Squeeze cementing is a common technique, and in the bullhead method, cement is pumped from the surface and forced down the wellbore by pump pressure. In the braidenhead method, pressure is placed at the surface from the casing valve.

The balance method is frequently used to place middle plugs. In the balance method, cement slurry is placed through a tremie pipe by pumping a calculated slurry volume through the pipe equal to the height of the slurry remaining in the pipe following placement. The cement falls out of the pipe filling the void as the pipe is removed. Fluid spacers may be used both ahead and behind the cement slurry to aid in placement. The use of coiled tubing to set plugs is attractive from both economic and operational standpoints because of its widespread application in workover operations.

The dump bailer is a tool that contains a measured quantity of cement that is lowered into the wellbore on a wireline and is opened on impact or by electronic activation. The use of a dump bailer allows precise control in placement since it is run on a wireline to location, but because of its limited carrying capacity, is not efficient when several zones or large volumes of concrete are required. If dump bailer methods are applied in federal waters they need to be placed in conjunction with a cast iron bridge plug.

The jet grouting technique is used when it is not possible to remove uncemented casing. In jet grouting, a high pressure stream of sand-laden water is used to cut the casing, and then cement grout is applied through the hole and into the formation.

4.3.3.5. Mud Program

All portions of the well that are not plugged with cement are required to be filled with fluid to control the possible influx of formation fluids into the wellbore. State and federal regulation differ somewhat in the fluid that is to be placed in the intervals between plugs. Federal regulations require that the fluid have the proper density to exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between plugs at the time of abandonment. The fluid can be mixed on-site or reconditioned drilling mud or completion fluid can be used.

4.3.3.6. Verification and Pressure Testing

To ensure proper plug placement, open-ended pipe or wireline tools are employed to tag the top of cement. The integrity of the plug can be verified using one of two methods. The MMS stipulates that the first plug below the surface plug and all plugs in lost circulation areas in open hole must pass a plug integrity test, involving:

- A pipe weight of at least 15,000 pounds on the plug; or
- A pump pressure of at least 1,000 psi with a pressure drop of not more than 10% in 15 minutes.

There are advantages and disadvantages of different methods. In the “pump and bump” method, the pipe concentrates the load on the area where the pipe touches the cement, while in the pressure method, pump pressure is exerted uniformly over the entire area of the plug (Field and Martin, 1997). Tagging is the least costly, especially for a bridge plug, but does not test the seal. The reliance on weight indicators may also not be accurate at 15,000 pounds and buoyancy factors and friction from the pipe-casing contact must be taken into consideration. Swab testing is another method for pressure testing cement plugs where the wellbore fluid is swabbed down until the hydrostatic fluid above the plug is below the reservoir pressure gradient of the zone.

4.3.4. Wellhead and Casing Removal

All wellheads and casing are required to be removed to a depth at least 15 feet (5 m) below the mudline unless the MMS District Supervisor approves an alternative depth. The District Supervisor may approve an alternate removal depth if:

- Wellhead or casing would not become an obstruction to other users of the seafloor or area;
- The use of divers and the seafloor sediment stability pose safety concerns; or
- The water depth is greater than 2,642 ft (800 m).

The salvage value of production tubing is usually insufficient to justify removal of the entire string, and if NORM scale is present in the tubing, removal will result in NORM waste that must be handled in accordance with federal guidelines. After wells are plugged and casing tubing cut and pulled, a sand cutter or mechanical cutting tool may be run downhole to cut the conductors, or depending on the preference of the operator and configuration of the platform, may subcontract for abrasive or explosive severance methods. In a typical mechanical operation, the tubing and production casing is first cut using a jet cutter – a small explosive blast that utilizes less than 5 pounds explosive – and then the strings are cut out from the inner tube using a mechanical cutter.

Conductor severing and recovery may be completed as part of P&A activities unless the platform configuration, equipment availability or scheduling prevent the operation. Conductors are configured in various diameters and wall thickness and are characterized by their inner casing strings, the location of the strings relative to the conductor (eccentric vs. concentric), and the application of grout within the annuli. Conductors are usually cut with mechanical methods or explosive charges. Mechanical methods are commonly applied during P&A activity, while if conductors need to be cut when the derrick barge is on-site, explosive charges will probably be employed to minimize standby time.

4.3.5. Reporting Requirements

Within 30 days after a well is plugged, the operator updates form MMS-124 and provides information on the operation, including final well schematic; description of the plugging work; nature and quantities of materials used in the plug; casing string cut and pulled, including severance method, size and amount of casing removed, and casing removal depth. The District Supervisor reviews the documents and issues warnings of noncompliance (INCs) if proper procedures were not followed. If leakage is detected and a problem well is brought to the attention of the MMS at a later date, the operator is responsible for environmental damage.

4.4. Factor Description

4.4.1. Contract Type

P&A contracts are written on either a dayrate or turnkey basis and both types are popular in the GOM. Under a dayrate contract, the service company performs activities for a fixed fee per day worked under the supervision of the operator. The responsibilities of each party are specified in the contract. The contractor is normally responsible for service equipment, a fully staffed crew,[23] specified materials and supplies. The operator of the well will usually retain ownership of the wellhead and all tubulars (casing, tubing), and be responsible for the disposal of all fluids circulated from the wellbore and any other waste generated on location. Under a turnkey contract, the service company is paid a fixed fee (lump sum) in return for completing the job according to the contract specification. Turnkey contracts offer contractors incentives to finish a job in a timely manner, since the contractor retains the cost savings of early completion, but unless the job requirements are well-known, also exposes the contractor to additional risk in the form of capital, environmental, and technical risk, including weather, downtime, and problem wells. Because of the additional exposure, uncertainty, and potential cost overruns, turnkey contracts are priced at a premium relative to dayrate contracts. The risk premium will vary with the market conditions and experience of the contractor, job specification, and other, mostly unobservable, factors.

4.4.2. Job Specification

Jobs are classified as PA or TA operations. The number of sites per job and number of wells per site determines the total work requirement. A site may have more than one well to P&A, and if the job specification is such that a large number of sites are involved, economies of scale may result since mobilization/demobilization time would be reduced and the contractor is already "primed" for work. In the GOM, P&A contracts are frequently written on a site-by-site basis, and so economies resulting from reduced mobilization/demobilization are believed to be minor, but for jobs performed on more than five wells per location, depending upon the contract type, economies may result from learning, discounting, or a combination of these factors.

4.4.3. Well Complexity

Complex wells arise from a diverse set of factors, including the nature of the geologic formation, the depth of the target, the size of the reservoir sands, the trajectory of the wellbore, and the technology applied. Well complexity is difficult to quantify and frequently ambiguous because practices, opinions, and experiences among contractors vary so dramatically. Well complexity often refers to one or more attributes that, if present, would tend to lead to a more difficult P&A operation. Well complexity is not a uniquely-defined measure, and depends as much on the experience and planning of the service company as on the downhole conditions encountered. Typically, a complex well will have high deviations at the surface casing shoe, severe dog legs, or be extended reach. Liner, tubing strings with gas lift mandrels, submersible pumps, and packers can also create problems. Other difficulties may include sustained casing pressure,[24] hydrogen sulfide, parted casing, long term fishing, milling work, or repeated trips. Junk found in holes, or equipment which cannot be retrieved, can increase cost significantly.

4.4.4. Location

The location of the job determines the mobilization and demobilization time to and from the site. For most infrastructure in the GOM, it usually takes at most a day to arrive at site and to prepare for service, and so costs within the OCS are not expected to be strongly influenced by the

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[23] A 12-hour crew will usually consist of 3-5 personnel, including one supervisor, one pump operator/crew leader, one wireline operator, and 1-2 floorhands. A 24-hour crew will usually consist of 8-10 personnel.

[24] Sustained casinghead pressure refers to the occurrence of fluid pressure in the casing tubing or any outer annulus in a well. Wells with sustained casing pressure are considered to present a higher risk of leaking and additional monitoring requirements are necessary (MMS, 1998 and 1999).

distance to shore. The distinction between near-shore and far-offshore locations can be significant, however, and is important since the uncertainty associated with offshore operations are generally larger and of greater significance the farther offshore the activity occurs.

4.4.5. Water Depth

Water depth is often a primary variable in offshore construction and drilling activities since increasing water depth requires the size of the service vessel and rig to increase, reducing operational flexibility and increasing the cost of the operation. Water depth contributes to tripping times and may involve additional cement volumes. In water depth 400 ft or less, P&A activity is not expected to be a significant factor since this depth category is relatively homogeneous in terms of the type of rig required. For deepwater wells and subsea wellheads, water depth is expected to play an important role in the cost of the operation.

4.4.6. Age

The equipment and components of a well will deteriorate over time from corrosion, wear, etc. which may affect the ability of the work crew to perform P&A functions. In old wells, it is not uncommon to find downhole obstructions in the production tubing, leaks and corrosion. Not all components of a well have the same age, however, and so the age of a well can be ambiguous. A well completed 25 years ago, for example, could have a new tubing string installed from a recent workover. Without detailed knowledge of the well maintenance history, such information is inaccessible.

4.4.7. Preparation

The availability of good records is essential to planning and execution. If good records are not available or do not match the well configuration, planning success may be impacted. In old wells, records may not exist, and if they do, they often provide incomplete or inaccurate data to determine the downhole conditions. The long time lapse between well completion and P&A means that operations are often performed after the value of the reservoir is exhausted. Ideally, operators should develop an abandonment plan before the well is drilled, which should be updated when the well's mechanical configuration is changed (Kelm and Faul, 1999).

4.4.8. Problem Wells

Problems may arise in P&A activities that delay the operation. In situations where an obstruction prevents pumping, wireline is typically used to recover the obstruction or move it to a point where pumping can be conducted. Differences in fluid densities of the cement plug and the wellbore fluids can contribute to plug failures and inconsistencies may cause the cement to move down through the well fluid and become contaminated. Instability is also influenced by wellbore angle, workstring/hole diameter and wellbore fluid geologies. Unexpected configurations or wellbore conditions, such as holes in casing, can also adversely affect the abandonment operation and contribute to cost overruns.

4.4.9. Fluid Type and Severity

Wells produce fluids in liquid and gaseous form, and it is not immediately obvious if it is easier (cheaper) to P&A a gas well or an oil well. Wells with sour (sulfur rich) fluids would be expected to have accelerated corrosion rates and stress cracking, which depending on the age and wellbore construction, may impair the capacity to perform P&A functions. Components which feature corrosion resistant alloys can mitigate the effects of sour fluids to some extent.

4.4.10. Well Access

In normal operations, P&A activity takes place from a platform or workboat, with procedures and tools designed for vertical access. For structures destroyed in a hurricane, the wellbores are lying horizontally on the seabed in various states of damage, and often require specialized solution (Segura and Blanchard, 2008). The loss of a platform can be compensated by the use of a liftboat, and to gain vertical access to wellbores, conductors will need to be cut by divers. Diver cuts are more hazardous and expensive than mechanical cutting, and because of limited access and poor visibility, progress is often slow and personnel are exposed to more risk than under normal conditions.

4.4.11. Technology

The application and use of advanced technology varies with the contractor and job specification. Tradeoffs exist between the cost-saving potential associated with new technology versus the start-up cost of learning; e.g., multi-function fishing techniques can reduce the number of trips required to cut and recover casing and the wellhead assembly in deepwater operations, but is also more expensive and difficult to apply (Going and Haughton, 2001; Chong et al., 2000). Assessment of the impact of technology and advanced diagnostic tools is usually difficult to quantify.

4.4.12. Construction Practices

The well construction practices used in drilling and completing a well and decisions the operator makes during the wells production life can affect P&A requirements. If annuli are properly isolated during well completion operations and if the well is kept in good mechanical condition, the abandonment operation is usually relatively straightforward to perform.

4.4.13. Rig vs. Rigless Method

P&A operations can be performed using either rig or rigless methods. The method chosen is dictated by engineering requirements, contractor preference, and equipment availability. Both methods are popular in the GOM. The traditional approach involves using a rig with a derrick, drawworks and surface equipment, and precedes much like a normal workover operation. A liftboat may be moved to the job site or platform equipment may be available. Most subsea wellheads require a rig-based method. In the rigless approach, a crane is used to pull pipe, and coil tubing and wireline units are used to assist with the placement of cement plugs. Coiled tubing units can enter and exit wells faster, and the rigless technique is normally less expensive than the rig method.

4.4.14. Exogenous Conditions

Weather conditions, mechanical problems, and logistics can significantly impact the scope of offshore operations and in most instances are unpredictable. Weather is a factor in all offshore operations and weather extremes adversely affect labor productivity and increase downtime. Mechanical problems and logistics can be mitigated to some extent through preparation and proper contingency planning.

4.5. Descriptive Statistics

4.5.1. Data Source

The database for analysis was compiled from jobs performed by Tetra Applied Technologies, L.P. in the GOM from 2002 through 2007. The sample set consisted of 256 jobs and 1,156 wells performed across a wide cross section of operators ranging from midsize independents to majors. At the time of the analysis, the sample set for 2007 was incomplete, and so conclusions based on the 2007 data are not definitive.

Cost and operational data was collected by reviewing invoice and job reports for all offshore operations performed by Tetra Applied Technologies. Job reports describe the day-to-day (actually, hour-to-hour) operations performed and include information on contract type, operational activities and utilization of liftboats and workboats. Water depth was available for only a portion of the sample, and the job type was not described (TA or PA operation) for the majority of wells, although for some wells the job type could be inferred from the operational reports. Contract type was specified. Jobs mainly involved platform wells, and although several wells were performed using rigless techniques, the majority of the jobs used rigs. All of the jobs were performed in water depth less than 400 feet on dry trees. No subsea wellheads were abandoned.

For turnkey contracts, the total cost of the operation was employed as opposed to the revenue received (the contract bid).[25] The majority of the sample set represented P&A jobs performed on a stand-alone basis, but we included a dozen or so jobs performed as part of a total decommissioning operation since the data for the P&A activity was clearly delineated. Costs are reported as current (nominal) dollars and are not adjusted for inflation.

4.5.2. Notation

Plug and abandonment jobs are classified according to contract type, as dayrate (DR) and turnkey (TK), and in a category that does not differentiate between contract type (ALL). In the ALL category, dayrate and turnkey jobs are aggregated and contract type was not used as a distinguishing factor. The primary metrics describing the data include average cost per well, Avg_cost_well (Acw), average cost per day, Avg_cost_day (Acd), and average days per well, Avg_days_well (Adw). The standard deviation of Avg_cost_well, Avg_cost_day, and Avg_days_well are denoted as SD_Acw, SD_Acd, and SD_Adw. The number of jobs and number of wells are denoted as Number_jobs and Number_wells. The ratio Number_wells/Number_jobs indicates the average number of wells serviced per job.

[25] If a business is to remain profitable, the revenue received on turnkey contracts must, on average, exceed the cost of the operation. For the jobs reported in the data set, aggregate turnkey revenue exceeded aggregate cost, but on an individual job basis, revenue occasionally fell below reported cost.

4.5.3. P&A Cost by Contract Type

Over the time horizon 2002-2007, dayrate contracts comprised 116 jobs and 300 wellbores, and turnkey contracts comprised 140 jobs and 856 wellbores. Contract type is an important determinant of the cost of the operation. From 2002-2005, the average P&A cost for a dayrate contract was significantly smaller than the average turnkey cost, ranging anywhere from 50-65% less expensive (Table D.1). In 2006-2007, a dramatic reversal occurred, with average dayrate contracts exceeding the turnkey variety four times over in 2006 and almost double in 2007 (Table D.2).

A composite average P&A cost that aggregates dayrate and turnkey contracts exhibits more regularity over the same time frame since it averages across all jobs (Figure D.3). The annual increase in the composite P&A cost is shown in Figure D.4. Between 2002-2007, the average increase in the composite average P&A cost was 11.3%.

The structural shift in cost that occurs between 2002-2005 and 2006-2007 is believed to be due to the confluence of three factors. The first factor is the impact of scale on P&A operations. Turnkey contracts averaged 3.4 wells per job in 2002, 4.3 wells per job in 2003, 4.7 wells per job in 2004, and 5.9 wells per job in 2005. During this same time horizon, between 1.2-2.5 wells per job was plugged under dayrate contracts. In 2006, because of the devastation brought by Hurricanes Katrina and Rita, damaged structures required wells to be abandoned in much greater quantity. It appears that turnkey operations were the favored contract type. Well owners preferentially select turnkey contracts for large well inventories, old wells, or complex operations. The total number of jobs did not increase significantly from previous years, but the number of wells per job increased substantially (averaging 15.6 wells per job). Scale effects become significant when 5 or more wells are plugged per job, where a 50% cost savings per well is not uncommon.

The cost increase observed in the dayrate contracts in 2006-2007 is due to the unusual level of competition for services. After the storms of 2005, competition for labor, equipment, and vessels in the GOM rose dramatically, increasing vessel dayrates two or three times historic levels. Turnkey jobs are affected by the same competitive pressures impacting dayrate contracts, but scale economies appear to be the moderating factor.

The third factor contributing to cost differences between contracts types and across years is related to the type of job performed, whether the operation was a temporary abandonment or a permanent abandonment. Unfortunately, this information was not captured in the sample data to the extent required for analysis. TA jobs are easier and cheaper to perform that PA jobs, and it is known that a significant number of P&A operations performed in 2006 were TA jobs. TA jobs performed under a turnkey contract will accentuate cost differences and contribute to a lower relative value, for all other things equal, but the magnitude of the contribution cannot be assessed without more complete data.

4.5.4. Daily Cost

The average cost to P&A a well expressed on an equivalent dayrate basis is shown in Figure D.5. The metrics are closely, but not perfectly correlated, across time. From 2002-2005, the average daily cost to perform P&A activity ranged from 5,600-13,000 \$/day for dayrate contracts, 15,800-22,300 $/day for turnkey contracts, and 11,800-17,200 $/day for the composite category (Table D.1). In 2006, the average daily cost increased significantly across both contract types, to $28,000/day for dayrate contracts and $23,200/day for turnkey contracts (Table D.2). The composite category averaged $26,100/day in 2006. High dayrates have continued into the 2007 season, reflecting the continued strong demand for labor and service vessels in the Gulf of Mexico, but shows signs of returning to more moderate pre-hurricane levels. The 2002-2005 period showed steady, moderate inflationary pressures on daily cost, while 2006 was exceptional because of the hurricane destruction and its impact on the service market. Moderation in the daily rates is evident in 2007 and is expected to continue in the future.

4.5.5. Average Number of Days

The number of days to P&A a well has been relatively stable over the past 5 years, averaging about 10 days per well, except in 2006, when a large volume of wells were plugged under turnkey contracts at an average rate of 2.4 days/well (Table D.1). It is likely that many of the wells plugged in 2006 were TA operations, which would partially explain why the performance metrics were so favorable.

4.5.6. Composite P&A Statistics

The average cost to P&A a well under a turnkey contract over the period 2002-2007 is slightly greater than under a dayrate contract, but as we have previously shown, the composite statistics mask important trends that have occurred over the past five years. The standard deviation of the Acw statistic is about 10% of the mean value indicating a reasonably well-defined metric over the time horizon. The 5-year average cost to P&A wells is $17,900/day, and it takes about 9 days per well to perform the operation (Table D.3). Turnkey contracts that Tetra writes typically service about twice as many wells as dayrate contracts per job (6.1 vs. 2.6).

4.5.7. Total Cost Correlation

The total cost to perform P&A operations depends on a number of observable and unobservable factors. Methods to predict the total cost of a job based on a small number of recorded variables are only expected to be reliable "on average" over a large number of jobs. One of the simplest ways to "forecast" the cost of a P&A operation is to correlate the total cost of the activity with the number of wells per job, and if one wanted to estimate the required number of days to perform the operation, this would likely improve the forecast (but unlike the number of wells of a job, the number of days to perform the activity is uncertain).

In Table D.4 and Table D.5, regression models for total cost are depicted using the number of wells and the number of days per job as the descriptive variables. We estimate the model with and without a fixed term coefficient, and decompose the data according to contract type. The correlations are based upon the complete data set with no inflation adjustments. The output statistic is measured in terms of $1,000.

In Table D.4, total cost is correlated with the number of wells per job, as follows:

Dayrate Contracts: Total_cost = 102.6 NW

Turnkey Contracts : Total_cost = 65.7 NW

All Contracts: Total_cost = 69.3 NW

In Table D.5, total cost is correlated against the number of wells of the job and the number of days to perform the service, as follows:

Dayrate Contracts: Total_cost = 5.5 ND + 56.8 NW

Turnkey Contracts : Total_cost = 18.4 ND + 9.6 NW

All Contracts: Total_cost = 12.6 ND + 24.4 NW

The model without the fixed term is more robust in all the formulations.

4.6. Scale Economies

Jobs are typically performed at a specific site. In some cases, contracts may be let on a field or area-wide basis, with wells located at several sites. As the number of wells in a job increases, there are at least two reasons why unit cost for P&A operations may decrease. If learning effects are present for multiple well operations, then as the contractor performs the service, they may become more efficient and this should be reflected in the total cost. Another reason why scale economies may occur has to do with discounts that contractors may offer operators on multiple well packages. In this case, the discount offered by the contractor to acquire the job, rather than any inherent learning, would be responsible for the cost reduction.

The job data was analyzed by contract type according to the number of wells per job, for [1] well jobs, [2-4] well jobs, [5-10] well jobs, [11-15] well jobs, and [> 15] well jobs. For dayrate contracts the results are mixed (Table D.6). The average cost per well does not exhibit a well-defined trend, but we observe that the average cost per well for jobs with [1-4] wells is somewhat greater than the larger well-count categories. For turnkey contracts, the results are unambiguous. As the number of wells per job increases, the average cost per well decreases significantly. The average cost per well for jobs with less than 5 wells is $177,000/well. For jobs with [5-10] wells per job, the average cost decreases to $90,000/well, a 50% decrease in unit cost from the [1-4] well job category. As the number of wells per job increases further, the unit cost continues to decrease, from $58,000/well ([11-15] wells) to $44,000/well ([>15] wells). Because of the well-defined trends in the unit cost data for turnkey contracts, it is likely that the cost savings are due to discounts offered to operators in price schedules rather than inherent learning effects.

4.7. Limitations of Analysis

The P&A job data reviewed in this chapter consists of a reasonably large and diverse sample, but because all the data is from a single contractor, the analysis may not be representative of the industry and some bias may be introduced into the results. We believe the benefits of using a consistent and homogeneous data set outweighs the drawbacks from the effect of potential contractor bias.

All the jobs were performed in water less than 400 feet deep and are representative of this water depth category. Deepwater wells and subsea wells are more complex to P&A, and in some cases, significantly more complex, so that extrapolation of the summary statistics to this water depth category is not valid.

The reported data did not allow us to differentiate between the type of operation performed under turnkey and dayrate contracts. In normal years, turnkey contracts are often used on complex wellbores or uncertain operations. During the aftermath of the 2005 hurricane season, turnkey contracts were also the preferred mechanism to help operators reduce their financial exposure and operational risk associated with clean up operations. Job requirements for TA operations are not as rigorous as PA operations, and so for all things equal, the average cost of a typical TA job would be expected to be less than a normal PA job. Unfortunately, the distinction between these operations cannot be distinguished from the data entries, and so we cannot assess the impact of this factor on the cost data.

It would be desirable to correlate P&A cost with the characteristics of the wellbore, job and contract type, and the technical aspects of the operation, but such a correspondence is difficult to realize due to the complex and uncertain nature of the operation and the lack of reliable data. Even if downhole conditions could be modeled accurately, the degree of uncertainty due to topside factors can only be reduced, not eliminated, so P&A cost estimation will always exhibit a degree of uncertain and unpredictable characteristics.

4.8. Conclusions

Plugging and abandonment operations are considered one of the more variable portions of decommissioning because it is influenced by a host of uncertain and unpredictable factors. We enumerated the primary factors that impact P&A operations and provided descriptive statistics and trend analysis for the time period 2002-2007. A significant amount of the variability and uncertainty of working offshore is not captured in the descriptive variables, and our inability to describe wellbore complexity and other attributes will impact how P&A cost can be modeled. Reliable and comprehensive cost data are for the most part not readily available in the offshore service industry, and so focused cost studies on particular segments of the industry can serve as a useful baseline. It is unlikely that “better” analytic models for P&A economics will be developed because of the nature of the operation. Cost functions provide an aid in cost estimation, and serves as a guide to quantifying and understanding the factors and processes involved in operations.

5. COST OF REMOVAL OPERATIONS IN THE GULF OF MEXICO

5.1. Introduction

Since 1973, nearly 3,000 structures have been removed from the GOM, and over the past decade, an average of 136 structures per year have been decommissioned. The purpose of this chapter is to assess the cost of removal operations in the GOM in water depth less than 400 ft. We review project data over the past five years from Tetra Applied Technologies L.L.C., one of the main decommissioning service providers in the GOM. Our data set covers 120 projects and 133 structure removals, and represents $178 million in total cost, the largest collection of decommissioned structures analyzed to date.

The outline of the chapter is as follows. We review the basic infrastructure used in offshore oil and gas development and discuss the factors that impact removal cost. We summarize cost data for preparation, pipeline abandonment, and removal operations across various levels of categorization, and construct empirical cost functions using regression analysis. Conclusions complete the chapter.

5.2. Offshore Infrastructure

The infrastructure required to produce oil and gas varies depending upon the time of development; the spatial distribution of reserves and reserves size; reservoir properties; water depth and expected weather conditions; cost of construction and decommissioning; seabed conditions; existing infrastructure; time to first production; equipment reliability; well accessibility; flow assurance; and numerous other (often conflicting) operating, economic, and strategic considerations. When planning any field development, the decision-making process attempts to maximize asset value and minimize costs without compromising safety or reliability.

5.2.1. Wells

Wells are used to access and extract hydrocarbons from one or more geologic formations. Drilling plans are devised based on the reservoir characterization and uncertainty. Successful exploratory wells will often be protected with a caisson or well protector prior to full field development, and as development wells are drilled, additional infrastructure such as platforms, subsea tiebacks, and pipelines will be installed.

Drilling and production operations are carried through rigid conductor pipes (conductors) which are driven into the seafloor and extend up to the deck level. Development wells are often drilled in a deviated direction or horizontally, and a number of sidetracks (multilaterals) may be associated with a wellbore. Wellheads located on a platform are called dry trees, and are accessed by a drilling or workover rig located on the structure, or by a jackup or liftboat if a platform rig is not available. A wellhead located on the seafloor is called a wet (or subsea) tree[26]

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[26] Subsea systems include seafloor and surface equipment. Seafloor equipment includes subsea wells, jumpers, manifolds, flowlines, and risers; surface equipment includes the control system and other production equipment located on a host platform. Umbilicals have multiple electrical and hydraulic conductors which provide data, control, and chemical injection functions to seafloor facilities.

and requires a floating rig. The number and type of wells associated with a structure is one indicator of structure complexity.

5.2.2. Caissons and Well Protectors

The basic size and function of an offshore structure result from the requirements of the development plan (McClelland and Reifel, 1986). Topside facilities define the function of the structure; the supporting substructure and foundation defines the platform type. In shallow water,[27] caissons, well protectors, and fixed platforms are the primary infrastructure used in field development strategies.

A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well (Figure E.1), while a well protector provides support through a jacket to one or more wells (Figure E.2). Production from caissons and well protectors is sent to a host processing facility on production platforms prior to being transported to shore. Caissons come in a variety of configurations, ranging from simple pipes to braced tripod structures with skirt pilings.[28] Well protectors consist of a welded tubular steel jacket that extends from the seafloor to above the waterline with hollow legs that provide a guide for driving piles. Caissons and well protectors have minimal production equipment and facilities.

5.2.3. Fixed Platforms

Fixed platforms resemble the jacket structure of well protectors, but are larger, more robust structures that include facilities for drilling, production, and workover operations (Figure E.3). Fixed platforms consist of three major elements: jacket, foundation, and deck. Jackets are prefabricated onshore in one piece, carried by barge, and launched at sea. Modern fixed platforms typically include structures with 4 to 8 legs, while many older platforms may have 10 or more legs. The deck section carries the functional loads for which the structure was built and is set on top of the jacket (Marshall, 2005).

Production platforms receive, separate, process, and export oil and gas. Risers are pipes that connect a wet tree, pipeline, or manifold on the seafloor to a production platform. Typically, a platform will have at least two risers clamped to the outside structure, one for the inbound flowline and one for the outbound pipeline. Multiple production risers may be employed for inbound flows, but more often, flowlines from individual wells enter a manifold, which will then be sent to the production riser. Export risers are used for oil and gas production, or for the injection of fluids into the reservoir.

5.2.4. Pipelines

Pipelines transport fluids between offshore production facilities or between a platform and a shore facility. Pipelines are classified into three categories: export lines, flowlines, and injection lines. Export lines transports processed oil and gas fluids between platforms or between a platform and a shore facility. The term trunk line usually refers to large-diameter pipelines that

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[27] Shallow and deepwater have different working definitions which evolve with time and vary with offshore basin. In the GOM, MMS defines shallow water as water depth less than 1,000 ft; deepwater as water depth greater than 1,000 ft, and ultra deepwater as water depth greater than 5,000 ft.

[28] Skirt piles are sometimes added at the base of a structure to increase the foundation capacity; they are driven through and grouted into guides, but do not reach the surface.

transport produced oil or gas to shore. A flowline is a pipeline that transports well fluids that originate at a subsea wellhead, manifold, or remote wellhead platform to the first downstream process component (API, 1999). Sometimes, depending on product quality, composition, and location, the produced fluid can be sent to shore or injected directly into an export line without processing. An injection line directs liquids or gases into a formation, wellhead, or riser to support hydrocarbon production activity (e.g., water or gas injection, gas lift, chemical injector lines, etc.).

Most flowlines and pipelines are composed of steel, but flexible pipe fabricated from metallic wires interspersed with thermoplastic layers may also be employed. Pipelines are characterized by their grade of steel, diameter, length, wall thickness, and many other factors. Gathering lines are typically short segments of small-diameter pipelines that can be as small as 4 to 6 inches, or as large as 12 inches. Subsea pipelines generally range from 12 to 36 inches. Typically, the diameter of the lines become larger the further downstream from the wellhead as more streams commingle. Pipelines are sized to handle the expected pressure and fluid flow of field production, but as production changes in quantity and location, pipelines may be converted, upgraded, extended, or looped. OCS pipelines may join pipelines carrying production from state waters to processing facilities or distribution pipelines located near shore or farther inland.

5.3. Cost Categories

Decommissioning operations in general, and removal activities in particular, involve a number of tasks that may be reported and categorized in various ways. Operations involve the mobilization/demobilization of multiple vessels, preparation activity, diving services, explosive services, conductor removal, pipeline abandonment, and waiting on weather. The manner in which costs are allocated across activity and category depends upon the requirement of the job and company accounting system. In our assessment, we aggregate cost across three categories: (1) structure preparation, (2) pipeline abandonment, and (3) structure removal. Activities that overlap more than one category are allocated in proportion to effort.

5.4. Factor Description

The time and cost to perform decommissioning activities depends on a number of factors. Several characteristics are observable, while many others are not, and there is no way to identify and measure all of the factors that impact operations. Removal operations are complex and subject to conditions specific to the job; simple causal relations are therefore usually inadequate to capture the drivers of cost variability. We provide a list of factors that impact the cost of removal operations, and although the list is not complete, it is meant to provide an indication of the complexity and uncertainty of operations. The factors we describe include the physical characteristics of the structure and pipeline, location, structure disposition options, company type and preferences, market conditions, deconstruction practices, the occurrence and duration of exogenous events, and contract specifications.

5.4.1. Structure and Well Type

Offshore structures and wells are classified according to their degree of complexity; structures are classified as caissons, well protectors, or fixed platforms; wells are classified as dry trees and wet trees, as defined previously. Each structure is associated with a certain number of dry and wet trees. As the complexity of the structure and well type increases, and with an increase in the number of wells, we would expect the cost of removal[29] to increase because the size of the rig and the time of the operation are roughly proportional to these factors.

5.4.2. Structure Characteristics

Deck size and weight; jacket size and weight; the number of piles, skirt piles, and conductors; and the diameter and weight of piles and conductor strings are the physical characteristics of offshore structures which impact the cost and time of removal.

Structural components that need to be removed are often large and heavy. Deck weight varies with the configuration type, the number and size of casing strings, and production capacity. Jacket weight varies with water depth, deck weight, and production capacity. The size and weight of the deck and jacket are important parameters since they determine the size and type of construction equipment required for the operation. Derrick barge (DB) selection is determined by the water depth in which the DB can safely operate, the lift capacity of the cranes, and market availability. The minimum DB required is determined by the maximum load weights[30] expected during the operation.

The conductors may contain multiple strings of well casing grouted together and with voids, and mechanical casing cutters, abrasive water jets, or explosives are used to make the cuts at the designated elevation. The number of conductors and their length determines the number of sections to be cut, stored, and offloaded, which in turn influences the type of cargo barge required and the time at site.

Piles and skirt piles anchor the jacket to the seafloor and may be grouted. Piles need to be cut and removed prior to lifting the jacket. Problems during severance (incomplete cuts) will impact the time at site.

5.4.3. Pipeline Design

Water depth, pipeline length and diameter, and the number and type of connections are primary factors in determining pipeline abandonment cost. Water depth places a physical restriction on the amount of time divers can safely work and will determine the type of dive support vessel required for the operation; the length, diameter, and type of pipeline determines the volume of fluids required to clean the line; and the number and type of connection, if a subsea tie-in or pipeline lateral, for instance, will determine mobilization and operation time.

5.4.4. Location

Location is an important factor in removal operations since location determines the distance to shore, water depth, and proximity to reef sites. Distance to shore is an important characteristic

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[29] The cost to plug and abandon wells is not part of our cost assessment. For further details on plugging cost, see Chapter 4 and (Kaiser and Dodson, 2007).

[30] In shallow water, the deck is normally the heaviest lift, but as the water depth increases, jacket weight normally exceeds deck weight. Lifts must be engineered to ensure the operation is performed within the capacity of the crane. The load weight and dimensions, center of gravity, rigging, and crane capacity limits are charted to verify that the crane can safely complete the lift.

since it determines the time and cost for mobilization/demobilization, offloading and transport, and service cost. The location of the structure relative to shipping lanes and artificial reef sites also impact the removal options available to the operator, and subsequently, the cost of removal.

5.4.5. Water Depth

Water depth dominants process, design, and economic considerations in field development, and is a primary variable in offshore construction activities since increasing water depth generally requires the size of the rig and marine vessel to increase, reducing operational flexibility, and increasing the time and cost of the operation. Water depth correlates with the size and weight of the structure, increasing the size of the DB required in removal operations. Increasing water depth will also increase the sensitivity of the operation to environmental factors.

5.4.6. Removal Method

Removal alternatives are generally classified as total removal, partial removal, and toppling in-place. A structure "toppled-in-place" proceeds much like a complete removal operation, except that after the piles are cut and removed, the structure is pulled over and placed on its side on the seafloor (Figure E.4).

All Gulf coast states maintain artificial reef programs, and to date, more than 200 offshore structures have been converted to reefs, representing about 20% of the total number of structures decommissioned since rigs-to-reefs programs were created. Operators that transfer a platform into an artificial reef reduce the cost that they would incur in bringing the platform to shore, and the usual practice is for the state and operator to split the savings. Most rigs-to-reefs structures are located offshore Louisiana (125) and Texas (73), with smaller numbers scattered across Alabama, Mississippi, and Florida. Louisiana has designated nine approved sites for the disposition of artificial reefs (Wilson and VanSickle, 1986), while Texas uses an exclusion approach, under which any area is assumed to be an appropriate site unless excluded because of alternative uses such as navigation or pipeline lanes (Stephan et al., 1996). The likelihood a structure is converted to an artificial reef increases with the water depth and varies with the planning area (Kaiser, 2006b).

5.4.7. Hurricane Destroyed Structures

Structures destroyed in a hurricane are found lying horizontally on the ocean floor, often in a tangled web of steel. The risk and cost involved in decommissioning downer structures are significantly higher than under normal conditions, ranging between 5-50 times more[31] than conventional abandonment, as discussed previously. The timetable for decommissioning depends on whether the lease is on production. If the structure is on a producing lease, owners have greater flexibility in scheduling cleanup and decommissioning activities, which will usually translate to cost savings.

5.4.8. Reuse Markets

The physical characteristics of the structure and the timing of their availability determine reuse opportunities. Reuse markets for decks, piles, conductors, and jackets are generally fragmented and thin, and as the age of a structure increases, the likelihood its equipment, deck, or jacket will

[31] Abandonment cost estimates for hurricane destroyed infrastructure has not been made public because of concerns of litigation and ongoing insurance claims.

be re-used greatly diminishes due to the costs of refurbishment. The evolution of stricter technical standards has also limited the re-use opportunities of equipment. Unless an operator has or knows of an upcoming field development whose parameters approximately match the facility to be decommissioned, immediate reuse of the deck and/or jacket is not likely to be successful. The refurbishment cost of old structures and equipment is likely to be excessive and structural specifications may not match available opportunities. Timing and scheduling present additional complicating factors for reuse opportunities.

5.4.9. Environmental Conditions

Wind, waves, current, and weather impact offshore operations in the GOM throughout the year, especially during the peak hurricane season, August 15 to October 15, and the winter season, November 30 to March 31. Although the offshore industry is known for its ingenuity, technological advancements and ability to withstand harsh environments, extreme weather is one factor that cannot be overcome, and during this time construction activities are particularly at risk. Ocean forecasts are not as reliable or accurate as land-based forecasts, and the ability to mitigate risks through avoidance scheduling and long-term planning remains significantly constrained. Weather may delay an operation or require the crew to demobilize to shore. The party exposed to weather risk will usually require a higher risk premium to manage the potential cost overruns.

5.4.10. Technology Options

The application and use of advanced technology varies with the contractor and job specification. A tradeoff usually exists between the cost-saving potential associated with new technology versus the premium of application and the additional cost of learning. The removal of offshore structures uses equipment and technology that has not changed for decades, and involves heavy lift vessels, cranes, diving services, and underwater cutting equipment. In shallow water, it is unlikely there will be significant opportunities for the development of new technology for these activities.

5.4.11. Exogenous Conditions

Technical complications may delay the operation, especially if site conditions differ from the contract specification. “Extra work” rates normally apply outside the turnkey contract. Failure to cut and the associated contingencies are normally specified in the contract terms. The use of explosives to cut piling and conductors requires the water column and general vicinity of the structure to be clear of mammals and sea turtles. If mammals or sea turtles are spotted in the vicinity of the structure prior to the detonation, regulations ensure that the marine life is not harmed. If the jacket is unable to withstand the stresses of removal, additional work will be required to reinforce the structure before lifting. Jackets that break or fall during removal will increase the cost of the operation.

5.4.12. Management Decisions

Management decisions regarding how a field is abandoned are reflected in the manner structures are grouped for abandonment, the value of deferred removal, and ultimately, the terms of the contract. The salvage value associated with the equipment, deck, and jacket will impact the net removal cost, depending on what party takes title to the structure components.

The project management team overseeing the decommissioning activities, in consultation with the operator, prepares the bid package and specifies the work requirements to be performed. This information will include special requests, such as platform and jacket disposition, and preference (if any) for the severance method to be employed. The operator may also have special concerns or preferences that dictate that a specific method be employed,[32] which will impact the cost of the project.

5.4.13. Company Type

Companies approach decommissioning from different operating philosophies and business models which may lead to different cost structures. Small companies tend to be cost-minimizers, while large companies tend to focus on risk management, and these alternative perspectives will impact the cost of the operation. Large independents and majors often approach decommissioning in a planning intensive and comprehensive manner. Large companies tend to be concerned with potential future liabilities, and because they are usually faced with greater public and government scrutiny, approach projects with greater caution and different expectations and requirements. Independents tend to want to get the job done quickly and efficiently at minimum cost, and because their activity is generally subject to less scrutiny, may not plan as extensively as majors.

5.4.14. Project Management Experience

The experience and expertise of the project management team overseeing the operation is an important factor in managing cost and ensuring the removal plan satisfies the company objectives. The project management team may be outsourced to a third party or be created from within the organization. The decommissioning team is responsible to: examine all available alternatives for decommissioning; group similar salvage and capital tasks into common work packages to achieve scale economies and shared mobilization costs; complete work packages with minimum cost equipment spreads; utilize regulatory options available to perform the scope of work; and maximize the value of salvaged structures, pipelines, and equipment. In the bid selection process, the project management team is not necessarily a cost minimizer, since other factors play a role in the selection decision, including operator preference, management expertise, contractor reputation, and past experience.

5.4.15. Market Conditions

The market supply and demand for vessels at the time of the operation is an important factor in determining cost. Derrick barges are large, ocean-going vessels that are usually towed by tugboats and equipped with revolving cranes built into the hull of the vessel. Crane capacity on a lift boat ranges from 10-70 tons, while a small DB can range from 150-300 tons. Large hull vessels have crane lift capacities of 600-1600 tons. A few large DBs in the GOM have lifting capability greater than 2,000 tons. The numbers of vessels available at any point in time change with the local supply and demand conditions and the ease in which vessels can be transported

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[32] For example, between November 15, 2000 – August 1, 2002, some operators (e.g., Shell, ExxonMobil, El Paso) specifically requested that contractors use nonexplosive methods for cutting because federal regulations concerning the incidental take of bottlenose and spotted dolphins expired and the National Marine Fisheries Service (NMFS) could not issue Letters of Authorization for structure removal activities. As a result of the expired regulation, operators were potentially exposed to penalties and could be held criminally liable should a take be recorded due to an underwater detonation.

between offshore region. Market rates for DB spreads depend upon depth rating and crane vessel capacity.

5.4.16. Contract Specification

Removal contracts are most often written on a turnkey basis that includes weather downtime, except downtime due to named tropical storms, for work during the prime season (May 15 to October 15). In a turnkey contract, the service company bids a "lump sum" for the completed job. A lump sum optional bid may also be offered which gives the contractor the ability to quote an alternative decommissioning method not specified in the scope of work but which still meets all specifications and goals of the job. Depending upon the cost, operator preferences and perceived risk of the operation, the decommissioning mode will be selected and the contract specification written.

The team in charge of structure removal will let contract according to one or more functional activities. The project management team specifies the work requirements of the bid based upon the information available at the time. In most cases, the contractor is responsible to furnish all labor, equipment, and material, including a crane vessel with sufficient capacity, cargo barges, tugs, and necessary construction equipment to perform the operation. The base bid will normally assume that the contractor will dispose of all platform components, while the operator will accept the cost of the NMFS observers and aerial survey required for the use of explosives, and any delays associated with the severance specification.[33]

5.4.17. Negotiation

Each contract is site, time, technology and operator specific, and so it is difficult to quantify the final negotiation process that occurs. In general, however, the operator will try to write a contract as specific as possible to eliminate contingencies and minimize the cost/risk of unforeseen events. Contractors prefer operational flexibility, a wide time window, and contingencies when uncertainty exists. A wide time window allows contractors to schedule operations to efficiently use their service vessel fleet, allowing them to bid more competitively and ensure extra time for unforeseen events. Contractors also prefer the operator to accept any unexpected cost/risk associated with the operation; e.g., if explosive methods are used, the operator will frequently incur all the cost associated with marine observers, aerial surveys, diver surveys, as well as any delays associated with the presence of sea turtles, marine mammals, nighttime restrictions, pile flaring, etc. The final negotiation is a give-and-take process based upon the contract terms, precedence, market conditions, negotiation strategy, and the history of the relationship between the operator, project management team, and contractor.

5.5. Descriptive Statistics

5.5.1. Data Source

The database for analysis was compiled from jobs performed in the GOM by Tetra Applied Technologies L.L.C. between 2003 and June 2008. 120 projects consisting of 133 structure removals were examined. In total, 20 operators were serviced, mostly large and medium-size

[33] The contractor generally will specify the severance procedure to be used and may provide various options if requested by the operator. If the operator specifies the severance method, this may result in the contractor qualifying the bid to transfer the severance risk to the operator.

independents, and one major. All costs are reported as current (nominal) dollars and are not adjusted for inflation. No additional processing of the data, "outlier removal," or specialized statistical analysis was performed. Reported cost of the sample set totaled $178 million (Table E.1).

Cost and operational data was collected by reviewing invoice, job, and accounting reports. A database was created with structure location, customer, work performed, year of operation, total job cost, cost by work performed, contract type, structure type, number of structures, number of piles per structure, number of conductors, structure disposition, deck and jacket weight, vessels employed, and activity duration. Comments on the nature of the activity (e.g., hurricane destroyed structure, inclement weather, lift problems, etc.) were also recorded.

All jobs were performed in water depth less than 350 ft and on a turnkey basis. The majority of the sample represented projects involving one structure, but in a few instances, two structures per project were removed. Work activities were described in terms of preparation, pipeline abandonment, and removal services with cost reported per activity. Not all jobs recorded costs for all categories; deck and jacket weight was also not available for all projects.

5.5.2. Categorization

Structure type and water depth are the primary categories employed, but we also group and analyze projects according to number of piles, structure disposition, weight, and duration. Water depth and structure type proxy weight, design and complexity characteristics, but a large degree of variability is unaccounted for due to age, production capacity, structure reconfiguration, etc. Ideally, we would like to group structures into families with similar jacket and deck weight, design characteristics, number and type of wells, etc., and then compute average removal cost within these individual categories. The difficulty with this approach is that as additional constraints (categorization levels) are imposed, the number of elements within a given category will decline, and with it the minimum size for reliable statistical inference. In other words, with each new layer of categorization that we add, the sample sets will decrease to a point where they may only be populated with a few elements, limiting the generality of the results.

5.5.3. Structure Preparation

Caissons and well protectors usually do not require preparatory activities, and in our sample, only one caisson reported preparation cost. If the operator prepared the structure for removal or employed a third party, then the removal contractor will not need to perform this service and no cost will be reported. Based on 35 job reports, the average preparation cost for fixed platforms ranged from $79,000 to $242,000, depending on water depth (Table E.2). Average preparation cost across all water depth categories is $130,000.

5.5.4. Pipeline Abandonment

Thirty-one projects reported pipeline abandonment cost (Table E.3). Abandonment cost increased with water depth and averaged $272,000 per structure across all water depth categories. Standard deviations per sample set are the same order-of-magnitude as the average, indicating that for all practical purposes, pipeline abandonment cost is not adequately captured by the water depth categorization. No additional factors on work activity (e.g., pipeline size, length, connection type, etc.) were available for analysis. Pipeline abandonment cost in 2003-

2008 ranged between 1.2-3.3 times greater than cost reported for similar categories from the period 1998-2003 (Kaiser et al., 2003).

5.5.5. Structure Removal

The number of structures removed by water depth and structure type is shown in Table E.4. In total, 133 structures were removed in 120 projects with over half of the structures involving fixed platforms (80), followed by caissons (38) and well protectors (15).

5.5.5.1. Average Cost

Average removal cost per water depth and structure type is shown in Table E.5. The removal cost of caissons and well protectors increase with water depth. The average cost to remove a caisson in 0-100 ft is $500,000; in 101-200 ft, the average cost more than doubles to $1.2 million. Removal cost for fixed platforms range from $865,000 (0-100 ft) to $2.6 million (201-300 ft) and are about 1.5 times the cost of caisson removal. The standard deviations per category are large and frequently about half of the average – especially as the water depth increases – indicating that the water depth and structure type categorization is doing a somewhat better job of "explaining" the variation in the sample data.

We expect removal cost to increase with water depth and structure complexity because the size of the rig and the time of the operation are roughly proportional to these factors. However, recognize that our results are sample dependent and may yield significant individual variations.

In Figures E.5 and E.6, the average removal cost of caissons, well protectors, and fixed platforms are depicted in terms of water depth. We would expect fixed platforms, because of their variation in size and complexity, disposition options, and nature of the operation, to exhibit larger spreads in costs than caissons and well protectors. This is demonstrated in the plots, but we caution that this is not necessarily a generalizable result. Cost data for structures with minimal complexity are more tightly grouped and exhibit a better statistical fit than the fixed platform data.

5.5.5.2. Structure Disposition

Removal cost depends upon the removal options available to the operator. Among the 80 fixed platforms removed, more than half were reefed in place or towed to a reef site (Table E.6, Figure E.6). In 0-100 ft water depth, about a third of the structures were reefed, which increased to 84% of removals in 101-200 ft and 94% in 201-300 ft. These percentages are slightly higher than aggregate GOM reef capture statistics (Kaiser, 2006b) and represent the individual characteristics and circumstances of the sample elements. Projects performed in deep water were more expensive than on-shore removal, perhaps due to the increased complexity of the operation and/or structure type (Table E.7). Without the reef option, the cost to decommission platforms would be even greater than the values depicted.

5.5.5.3. Platform Configuration

Removal cost statistics for structures grouped according to number of piles are reported in Table E.8. We employ 3-pile, 4-pile, 6-8 pile, and 8+ pile categories and compute average removal cost per category. The data exhibit reasonably consistent patterns across water depth and number of piles. For 3-pile structures, removal cost range from $654,000 (0-100 ft) to $1.67

million (201-300 ft), and as the number of piles per structure increased, there was an increase in cost with water depth. For 6- and 8-pile structures, removal cost ranged from $986,000 (0-100 ft) to $2.72 million (201-300 ft). The average removal cost of an 8+ pile structure is about twice that of a 3-pile platform.

5.5.5.4. Caisson Configuration

For caissons with skirt piles, removal cost ranged from $463,000 (0-100 ft) to $871,000 (201-300 ft). Caissons without skirt piles were more expensive to remove: $498,000 (0-100 ft) to $1.52 million (101-200 ft). See Table E.9. The sample size for the 0-100 ft category consisted of more than a dozen projects for each caisson type, and for these two categories, costs are quite similar. In the 101-200 ft water depth categories, the sample sets consist of less than 5 elements each, which may be partially responsible for the large differences observed.

5.5.5.5. Year of Removal

To underscore the variability inherent in the cost data, we consider the removal cost of fixed platforms over time. The number of fixed platforms removed per year is illustrated in Table E.10 and average removal cost is depicted in Table E.11. Average removal cost is generally increasing with water depth when sample sizes are sufficiently large, but across time, we observe the variation in cost that may occur. Unfortunately, it is not possible to precisely delineate why cost behave in this manner, but the usual suspects are believed to be responsible, namely, market conditions (supply and demand, which determine vessel dayrates), structure characteristics, and environmental conditions.

5.5.5.6. Total Cost

The total cost to remove a caisson and well protector is computed by adding pipeline abandonment and removal cost; and for fixed platforms preparation activity (Table E.12). We group caissons and well protectors together because they have reasonably similar functional characteristics and often do not require preparatory activity. For caissons and well protectors, the total cost of removal ranges from $686,000 (0-100 ft) to $1.5 million (101-200 ft). For fixed platforms, total removal cost ranges from $1.1 million (0-100 ft) to $3.5 million (201-300 ft).

5.5.6. Weight Relations

Various weight correlations can be examined depending on the availability and quality of the data. We focus on the deck weight to jacket weight ratio and total weight relations. In removal operations, it is the weight of the heaviest lift that will determine the DB required. Caissons and well protectors have minimal decks, and this is reflected in a deck-to-jacket weight ratio less than one (Table E.13). As foundations transect a larger water column, the deck-to-jacket weight ratio will decrease if the deck weight remains unchanged. If processing capacity and deck requirements change, then the ratio may increase. For fixed platforms in shallow water, deck weight usually dominates jacket weight, but as water depth increases, jacket weights will often exceed deck weight (Ellis and Shirley, 2005). The weight ratios depicted in Table E.13 is specific to the sample set, and because the sets are somewhat smaller than those used in the cost analysis, extrapolation of the relations to the GOM are questionable.

Average removal cost as a function of total weight (deck, jacket, piles, and conductors) is depicted in Table E.14. Caissons are 2-4 times more expensive on a per ton basis than fixed platform removals. The average removal cost per ton of fixed platform is depicted in Figure E.7.

5.5.7. Activity Duration

Job duration is defined as the number of work days spent on a job in executing a specific set of activities or operations. Duration includes the direct time spent on the job, as well as indirect time in preparing for the activity. Mobilization/demobilization time is included in the duration estimates. Duration is an important metric in offshore operations since if the market rates for the vessels required and the duration for the project can be reliably estimated, then job cost can be approximated. Unfortunately, significant uncertainty exists in both duration and market rate estimates, making the predictive capacity of these relations limited.

The average time to perform preparation, pipeline abandonment, and removal activities is shown in Table E.15 according to water depth. Projects which involve more than one activity (e.g., preparation and removal) which did not break-out duration per category occurred in less than 10% of the sample and were excluded from analysis. Preparation and pipeline abandonment time are roughly equal, but because of the higher dayrates associated with diving and associated support vessels, the cost of pipeline abandonment will usually dominant preparation cost. The time to complete removal activities increases with water depth, which mimics (and is the reason for) the increased costs reported previously.

5.5.8. Structure Installation

Removal operations are essentially the reverse of installation activities. The cost to remove a structure of a specific type in a given water depth should therefore approximate installation cost for a similar structure in the same water depth category. Tetra Applied Technologies performed 20 structure installations (3 caissons, 5 well protectors, 12 fixed platforms) between 2003-2008. The sample is small but is sufficient to compare relative magnitudes. The average cost to install a caisson range between $534,000 (0-100 ft) to $833,000 (101-200 ft) as shown in Table E.16. Well protectors and fixed platforms exhibit more similarities in installation expenditures than for removal operations, probably due to the pile driving requirements. For jacket structures installation cost range from $1 million (0-100 ft) to $2.8 million (201-300 ft), roughly consistent with the structure removal costs depicted in Table E.5.

5.6. Regression Modeling

The cost to remove a structure is described by a number of variables which are dominated by different factors at different times. For illustrative purposes we hypothesize[34] a linear function of the form:

[34] If interaction effects are believed to play a significant role, then a nonlinear specification can be applied: $TC=\alpha_0+\sum_{i=1}^{4}\alpha_i X_i+\sum_{i<j}\alpha_{ij}X_i X_j$.

$$TC = \alpha_0 + \sum_{i=1}^{4} \alpha_i X_i ,$$

where X_1 = *WD* = Water depth (ft), X_2 = *WGT* = Total structure weight (ton). X_3 = *NP* = Number of piles, X_4 = *DUR* = Duration (days). All the variables are numeric and the selection is based upon data availability, user preference, sample characteristics, and categorization level employed.

The total cost of structure removal is expected to increase with water depth and structure complexity, and so in a one-variable relation, the coefficient of the variable *WD* is expected to be positive and increase with complexity. In a multivariable model, we would expect cost to increase with total structure weight and duration. The nature of the sample set will dictate if specific relations hold.

Illustrative functional relations for removal costs are shown in Tables E.17 and E.18. The single variable cost models behave roughly as expected and exhibit reasonably good model fits and statistically significant coefficients. In the multivariable cost models, the results are mixed. Strong positive correlations are evident with duration and total weight. A negative correlation with number of piles reflects the characteristics of the sample data.

5.7. Limitations of Analysis

Decommissioning is governed by conditions unique to the structure, site, operator, and contractor, as well as the prevailing environmental, engineering, market, operational, and regulatory conditions at the time of the operation. The unique nature of offshore operations drives the variability observed in cost statistics, which can only be partially explained through factor analysis.

Sample select problems in statistics occur when the sampling is not random. In this study, all removal projects are performed by one service provider, and although they represent a large and diverse collection of structures and water depths, the observations cannot be construed as a random sample. Projects are performed by one company and represent mostly independent operators. We believe the data is representative of the independent sector but we cannot extrapolate our assessment to infer project cost for majors, except as a lower bound estimate.
All jobs were performed in water depth less than 350 ft. Deepwater and floating structures and subsea wells are significantly more expensive and complex to decommission, and extrapolation of the summary statistics outside the aforementioned categorization is not valid.

Decommissioning operations typically involve a number of activities which may overlap one or more categories, and if data is not properly reported and categorized, will bias summary statistics. Fortunately, because the cost data was complete and carefully recorded, we were able to minimize discrepancy and allocation bias in the study.

The data set was analyzed using standard statistical analysis. No additional processing of the data, "outlier removal," or specialized regressions was performed. The statistical measures are believed to be reasonably representative of the removal cost of independent operators in the shallow-water Gulf of Mexico.

5.8. Conclusions

Removal operations are usually the greatest contributor to the cost of decommissioning, and for this reason, it deserves careful and regular review. Removal costs are highly variable because the operation is influenced by a host of uncertain and unpredictable factors. We enumerated and described the manner in which various factors may impact removal operations and provided descriptive statistics for the GOM covering the period 2003-2008.

A significant amount of the variability and uncertainty of working offshore is not captured in the descriptive variables, and our inability to describe the characteristics of each operation impact the manner in which cost can be accurately modeled.

Cost estimates are judgments, made by managers and engineers, of the costs expected to arise based upon a comparison of similar projects, site characteristics, market conditions, and the collective experience of the estimator. Project managers try to manage and reduce uncertainty, but cost estimates will always be uncertain because of project uncertainties, unpredictable and uncontrollable conditions, and imperfect information.

6. COST OF NET TRAWLING OPERATIONS IN THE GULF OF MEXICO

6.1. Introduction

In the United States, federal regulations require that all wells and offshore structures in the OCS be completely removed to a depth 15 ft (5 m) below the seafloor within one year after production on the lease ceases. After wells are plugged and abandoned and the structure is removed, federal regulations require that the site be verified "clear" by an independent third party.

A variety of techniques may be used to perform SC&V operations, but net trawling and diver survey are the most common in the GOM. In diver salvage, divers identify targets and attach lift lines to the debris, and a crane on a surface support vessel lifts the debris from the water bottom and places it on deck for subsequent disposal on land. Net trawling uses conventional trawling techniques with a reinforced net assembly to pick up debris on the water bottom. Diving spreads typically perform many different services throughout decommissioning, and it is usually not possible to isolate clearance services from other activities, such as structure preparation, pipeline cutting, dredging, etc. For the purpose of cost benchmarking, it is preferable to analyze net trawling operations rather than diver surveys, since net trawling is well defined, focused exclusively on clearance and verification activity, and the data is transparent and easy to interpret.

The amount of time involved to clear a site depends on a number of factors that are uncertain and unobservable, such as the amount, size, and type of debris present at the site; the equipment available to perform the operation; and the weather conditions at the time of the activity. All of these variables are stochastic and unpredictable, while the factors that are observable – such as water depth, structure type, and age - are usually only weakly correlated with cost statistics. It is for this reason that the best estimates of cost tend to be based on descriptive statistics derived through the mean of the sample distribution.

The purpose of this chapter is to describe the cost of net trawling operations in the OCS of the GOM over the period 2001-2005. In previous work, cost statistics and regression models were developed for trawling operations performed between 1997-2001 (Kaiser et al., 2005). We update the cost statistics of net trawling covering a more recent time period and describe the factors that are expected to impact the cost of SC&V operations.

6.2. Factor Description

The amount of time involved to clear a site and verify clearance depends on the amount, size, and type of debris present; the location of the site; the equipment available to perform the operation; the clearance and verification techniques used; and the weather conditions at the time of the operation. A site may require different salvage techniques or a combination of techniques to remove debris. Each site is unique, and operators make decisions on which technique to employ based on their experience and knowledge of the site conditions.

6.2.1. Structure Type

The area that must be trawled for clearance and verification is determined by the structure type that previously occupied the site. Federal regulations require clearance operations centered on the well or the geometric center of the facility, with radius determined by the well or structure type: temporarily abandoned wells (working radius), delineation and exploration wells (300 ft radius), single well caissons and well protectors (600 ft radius), and platforms (1,320 ft radius).

6.2.2. Structure Complexity

Offshore structures perform a wide variety of functions, depending upon the field development requirements, and are constructed according to various tiers of complexity. A structure that is unmanned and serves in an auxiliary role, say as a compression station, meter facility, or storage site, is significantly less complex than a manned drilling and production platform with two dozen flowing wells. Complex structures, especially development and manned production facilities, are expected to have more debris at the work site relative to unmanned facilities, caissons and exploratory/delineation wells.

6.2.3. Clearance and Verification Techniques

Clearance may be performed with diver surveys, sweep assemblies and heavy duty trawl nets, electromagnetic and grappling devices, dredging buckets, or a combination of techniques (Pulsipher, 1996; Manago and Williamson, 1997). Diver salvage and net trawling are the most common approaches in the GOM. Clearance may be initiated with a survey to determine where the debris is located, or net trawling may commence without performing an initial survey, depending on operator preferences and the conditions (expected or known) at the site. If divers were previously deployed to clear the site, or if the structure is a caisson or delineation/exploratory well, then SC&V will usually be performed with a shrimper net. If pre-clearance operations were not performed, or if the structure is a production or manned facility, then clearance with a heavy duty net typically precedes verification with a shrimper net. Operations are performed sequentially and only for the verification survey does the area trawled have to be over 100% of the site.

6.2.4. Age

A steel structure in a salt water environment will deteriorate over time from corrosion and wear, depending on the type and quantity of steel used, the environmental conditions at the site, the application of sacrificial anodes, the manner in which hurricanes "use up" the fatigue life of the structure, and other factors. Old structures have more time to gather and collect debris, and a positive correlation would be expected to exist between the amount of debris and age.

6.2.5. Location

The location of the job where SC&V occurs impacts the mobilization/demobilization time to arrive at the site. For most infrastructure in the GOM, it takes at most a half-day (12 hr) to arrive on location, and net trawling can begin almost immediately. Since it normally takes between 2-6 days for trawling, service costs are not expected to be strongly influenced by the distance to shore. The distinction between near-shore and far-offshore activities can be significant, however, and is important since the uncertainty associated with offshore operations are generally larger and of greater significance the farther offshore the activity occurs.

6.2.6. Water Depth

Water depth is often a primary variable in offshore construction activities since increasing water depth requires the size of the vessel to increase, reducing operational flexibility and increasing the cost of the operation. For net trawling operations, however, the vessel size is fairly insensitive for water depth ranging up to 300 ft (91 m) or so. Water depth does contribute to the time to set and retrieve netting, and may be an important factor if a given depth threshold is exceeded; e.g., water depth greater than 300 ft (91 m) might necessitate using remotely operated vehicles or manned submersibles to remove debris.

6.2.7. Exogenous Conditions

Weather conditions, mechanical problems, and trawler damage can impact the scope of SC&V operations, and in most instances, are unpredictable. Weather is a factor in all offshore operations and weather extremes adversely affect labor productivity and increase downtime. Mechanical problems can be mitigated to some extent through preparation and proper contingency planning.

6.2.8. Strategic Decisions

Operators decide the manner in which a site is to be cleared, based upon experience and prior success of various techniques, technical information, and other factors. Cost is usually a consideration in decision making since operators want to fulfill the regulatory requirement in the most cost-effective and efficient manner.

6.3. Net Trawling Service Contracts

6.3.1. Contract Elements

Net trawling service contracts are typically written on a time and material basis with respect to the following elements:

A. Equipment and personnel, $\$K_1$/day,
B. Loss and damage, $\$K_2$/event,
C. Incidental, $\$K_3$/incident,
D. Document preparation, $\$K_4$/site.

The equipment and personnel dayrate covers the cost of the equipment and personnel to perform the service, and includes the mobilization/demobilization cost to/from the dock site; all personnel, equipment, and supplies such as fuel, nets, lubrication, food, water, and navigation; and trawling services performed at the site. A trawling vessel usually requires a four- or five-man crew for operation: a licensed captain, a surveyor, and two or three deckhands. The daily rate typically provides for 12 hours of trawling per day (6 am – 6 pm, or daylight hours).

Nets gather and collect all sorts of debris during clearance operations (Figures F.1 and F.2), and in the process, may be lost or damaged. A separate loss and damage charge is expensed depending on the type of net and if the damage is repairable. Two types of nets are commonly used – standard shrimper nets and heavy-duty "Gorilla" nets – and are priced according to the cost of repair or if lost/unrepairable, as follows:

$$K_2 = \begin{cases} K_{21}, \text{Gorilla - net repairable,} \\ K_{22}, \text{Gorilla - net lost or unrepairable,} \\ K_{23}, \text{shrimper - net repairable,} \\ K_{24}, \text{shrimper - net lost or unrepairable.} \end{cases}$$

Separate contract components cover boards, dummy doors, cables, chains, and buoys that are lost or damaged[35] at the variable rate \$ K_3 /incident. The company renting the vessel must arrange for the disposal of trash collected from the operation.

Document preparation and a close-out report on the trawling operation to MMS NTL 98-26 specifications is charged at a flat rate of \$ K_4 /site.

6.3.2. Total Cost

Job specification is defined by the characteristics of the well/structure that occupied the site and the type of service requested by the operator. Job *J* is characterized by a number of factors, but only a few variables are typically recorded, such as the structure type (caisson (*C*), well protector (WP), platform (*P*)), the age *AGE* of the structure upon removal, and the water depth *WD* at the site.

The total cost of job *J*, *TC(J),* is given by the value

$$\text{TC}(J) = K_1 TD + K_{21} GR + K_{22} GU + K_{23} SR + K_{24} SU + K_3 M + K_4 ,$$

where *TD* = total number of days from dockside, *GR* = total number of Gorilla nets repairable, *GU* = total number of Gorilla nets lost or unrepairable, *SR* = total number of shrimper nets repairable, *SU* = total number of shrimper nets lost or unrepairable, and *M* = total number of incidental events. The value of the parameters K_1, K_2, K_3, and K_4 are specific to the terms of the contract and vary over time.

6.4. Descriptive Statistics

6.4.1. Data Source

Data for 308 jobs performed by B&J Martin, Inc. over the five-year period from 2001-2005 comprised the sample set. Jobs classified as "partially" completed or "incomplete", and those operations sited in state waters, were excluded from analysis. To maintain the confidentiality of the data, no information regarding the operator was identified and only aggregate statistics are presented.

[35] Repairs to rigging or towing blocks caused by hang-ups are put out to bid. The company renting the vessel for SC&V is required to pay the diver expense if a net needs to be removed from the vessels propeller.

The total cost of each job was determined based on the price sheet for the year in which the job was performed. Price sheets describe the daily rate, loss and damage expense, meals and bunks, and report and track plot (Table F.1). Reported job data included *TD, GR, GU, SR, SU*. The value of *M* was not reported, and so the cost does not include the expense of loss and damage or diver expense associated with lost boards, cables, chains, damage to rigging, or other exceptional events. The total cost also does not include the cost to dispose of trash.

Cost was estimated based on the total number of days to perform the operation, the number of repairable and unrepairable nets, and the number of repairable and unrepairable Gorilla nets. The job statistics were multiplied by the appropriate unit cost factors and summed, and then the fixed cost of the track report was added. Daily rates start and end at dockside in Galliano, Louisiana, and standby rates at a lower basis apply in unusual conditions; e.g., repair to outriggers or towing blocks caused by hang-ups. Costs are reported as current (nominal) dollars and are not adjusted for inflation.

6.4.2. Operational Statistics

The total number of days to perform SC&V services for platforms is roughly twice the number of days for caissons (Table F.2). This result is partially explained by the greater amount of area that is required to be trawled for platform sites. For all other things equal (e.g., site location, age, amount of debris present, water depth), if the time to perform SC&V is determined entirely by structure type, then we would expect that the time to SC&V a platform would be about five times greater than a caisson since the trawling area for a platform exceeds the area for a caisson by a factor of about five.[36] All other things are usually not equal, however, and since many other factors play a role in the cost of the service, an attenuation of the theoretical value results.

A trawling vessel normally operates for 12 hours a day, and so the total number of days from dockside should exceed the total number of trawl days (*LD*) by a factor of about two. The impact of mobilization/demobilization to/from the site and variations due to the debris collected, weather conditions, time of year in which the operation is performed, etc. will force departure from this value. The ratio *TD/LD* ranges between 1.5-1.7 for the sample set (Table F.2). In Figure F.3 and Figure F.4, we plot *TD* versus *LD* for caisson and platform jobs to illustrate the spread of the data.

The number of nets damaged when trawling across former platform sites is greater than caisson sites by a factor of about two (Table F.2). Items collected provides some indication of the complexity of the task, but since the size, weight, and/or volume of the debris is not described; e.g., a tire and a 12 ft (4 m) long drill string both count as one item, this statistic does not provide a useful descriptor variable. For the most part, the average number of items collected as a function of structure type behaves as one would expect with old, complex, and manned platforms yielding the most debris, but this is by no means a universal characterization.

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[36] If A(P) and A(C) denote the clearance area required to be trawled for a platform and caisson site, then from the federal regulations: $\frac{A(P)}{A(C)} = \frac{\pi(1{,}320\text{ ft})^2}{\pi(600\text{ ft})^2} = 4.8.$

The use of Gorilla nets is often applied to older structures and platforms, and about 35% of platform jobs in the sample employed Gorilla nets. Only about 10% of caisson sites used Gorilla nets for trawling. It is unlikely that caissons will have debris that would necessitate the use of Gorilla nets, while for platforms - depending on the age, function, and prior clearance activities – Gorilla nets are more commonly applied.

6.4.3. Total Cost

The total cost of SC&V operations for caissons and platforms are tabulated in Table F.3 and Table F.4 according to jobs that employ only regular nets, jobs that apply Gorilla nets, and all jobs (regular and Gorilla net applications). The standard deviation of the total cost (*TC Deviation*) indicates the dispersion of the average. The variable *Percentage* reports the percentage of total cost that arises from the dayrate, which provides an indirect indication of the relative difficulty of the operation, since for difficult jobs, loss/damage will play a larger role in the total cost of the operation. *Percent Deviation* indicates the dispersion of the percentage variable.

The average cost to clear and verify a site previously occupied by a caisson is computed to be $15,964 (Table F.3). Total cost varies across time and depends on the type of net used, with average cost ranging between $14,302 (regular nets) to $26,369 (Gorilla nets). The value of the standard deviation is often one-half or more the average value, indicating significant variability across jobs. For platform sites, the average SC&V cost based on 141 jobs is $42,834 (Table F.4). Net type is a key determinant of cost, with average cost ranging between $32,036 (regular nets) to $63,119 (Gorilla nets).

Personnel and vessel cost constitute the majority of the service cost for regular trawling. The average service cost for regular trawling exceeded 80% for both caissons and platforms, while for Gorilla net trawling, loss and damage plays a more significant role and the dayrate percentage varied more widely, from 36-72% for caissons to 46-59% for platforms. The cost of consumables (loss/damage) for Gorilla net jobs represents a significant part of the job cost reflecting more demanding trawling conditions.

6.4.4. Water Depth Categorization

Average clearance and verification cost aggregated according to water depth is shown in Table F.5. Only a few jobs in the sample set were performed in water depth exceeding 250 ft (76 m), and so cost entries for this category remain uncertain. A significant cost difference exists between caissons and platforms, but across water depth, the cost is reasonably uniform across both structure types, indicating that water depth is not a significant factor in determining SC&V cost.

6.5. Conclusions

The cost of site clearance and verification operations in the OCS of the GOM was examined based on jobs performed by B&J Martin, Inc., from 2001-2005. Descriptive statistics for the cost data was reported, and the factors that are expected to impact the operation were described. Site clearance and verification costs are closely dependent upon the time to perform the service, which itself is unremarkable, since all service contract costs are highly dependent on the time of the activity. Service time is unpredictable, and so average cost decomposed according to structure type was shown to be a useful benchmark to gauge SC&V cost commitments. Water depth did not appear to be a significant factor in determining SC&V cost.

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APPENDIX A

CHAPTER 1 TABLES AND FIGURES

Table A.1.

MMS Approach[a] to Estimate the Total Decommissioning Cost per Leasehold

Decommissioning Stage	Water Depth (feet)	Estimated Cost[b] ($)
Plug & Abandon	all	100,000
Structure Removal	< 150	400,000
	151 – 200	600,000
	201 – 299	1,250,000
	> 300	2,000,000 +
Site Clearance & Verification	< 150	300,000
	151 – 249	400,000
	> 250	500,000

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) The P&A unit cost is per borehole, the structure removal cost is per structure, and the SC&V cost is per leasehold. The total lease liability is computed by summing the unit cost elements.

Source: MMS, 1998.

Table A.2.

Exploration and Development Wells Drilled in the Gulf of Mexico (1997-2007)

Water Depth (ft)	Exploration Wells	Development Wells
0-60	4,257	8,651
61-200	6,337	12,229
201-600	3,894	7,836
601-1,000	414	487
> 1,000	2,005	1,360
Total	16,907	30,563

Source: MMS, 2007.

Table A.3.

Structure Installations by Structure Type and Water Depth (1947-2007)

	Water Depth					
Structure Type[a]	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1970	488	4	0	0	2,462
FP/Manned	384	501	301	18	6	1,210
/Unmanned	860	1,135	301	3	0	2,299
/Total	1,244	1,366	602	21	6	3,509
CT	0	0	0	1	2	3
MOPU	2	2	0	0	0	4
SEMI	0	0	0	0	6	6
SPAR	0	0	0	0	14	14
SSMNF	0	1	0	0	0	1
SSTMP	0	1	1	0	1	3
TLP	0	0	0	0	10	10
WP	450	310	39	0	0	799
TOTAL	3,666	2,438	646	22	39	6,811

Footnote: (a) CAIS = caisson, FP = fixed platform, CT = compliant tower, MOPU = mobile offshore production unit, SEMI= semisubmersible, SPAR = deep draft floating caisson, TLP = tension leg platform, WP = well protector.

Source: MMS, 2007.

Table A.4.

Structure Removals by Structure Type and Water Depth (1997-2007)

	Water Depth					
Structure Type[a]	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1,084	283	2	0	0	1,369
FP/Manned	39	68	30	1	0	138
/Unmanned	393	523	127	0	0	1,043
/Total	432	591	157	1	0	1,181
CT	0	0	0	0	0	0
MOPU	0	2	0	0	0	2
SEMI	0	0	0	0	1	1
SPAR	0	0	0	0	14	14
SSMNF	0	0	0	0	0	0
SSTMP	0	2	0	0	1	3
TLP	0	0	0	0	0	0
WP	211	187	21	0	0	419
TOTAL	1,727	1,065	180	1	16	2,989

Footnote: (a) CAIS = caisson, FP = fixed platform, CT = compliant tower, MOPU = mobile offshore production unit, SEMI= semisubmersible, SPAR = deep draft floating caisson, TLP = tension leg platform, WP = well protector.

Source: MMS, 2007.

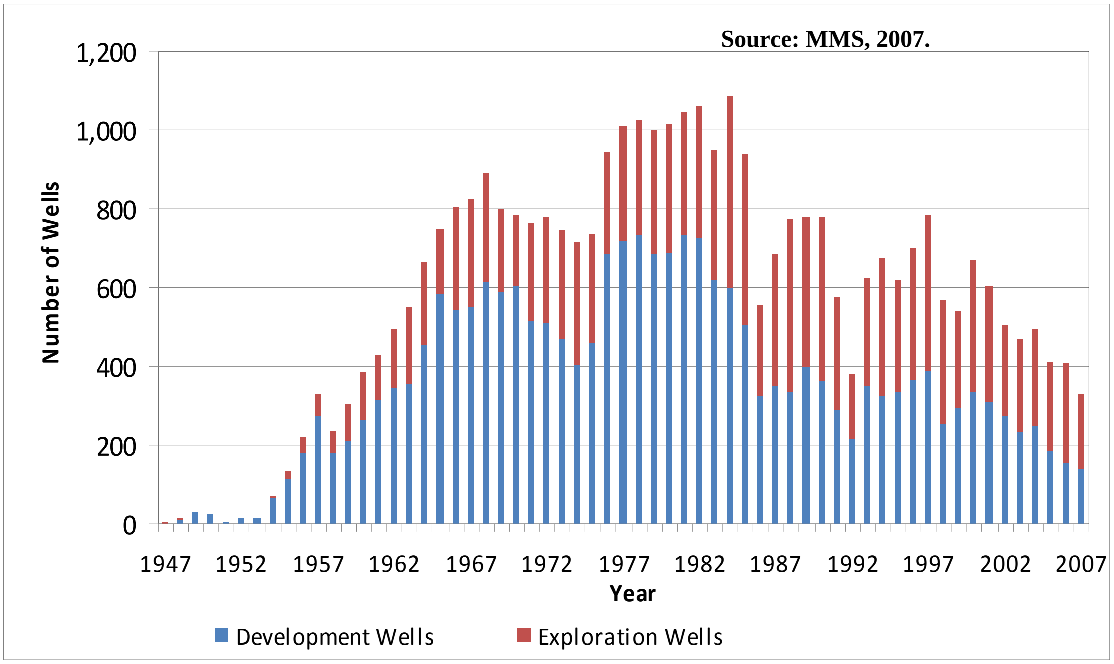


Figure A.1. Number of Exploration and Development Wells Drilled Annually in the Gulf of Mexico (1947-2007).

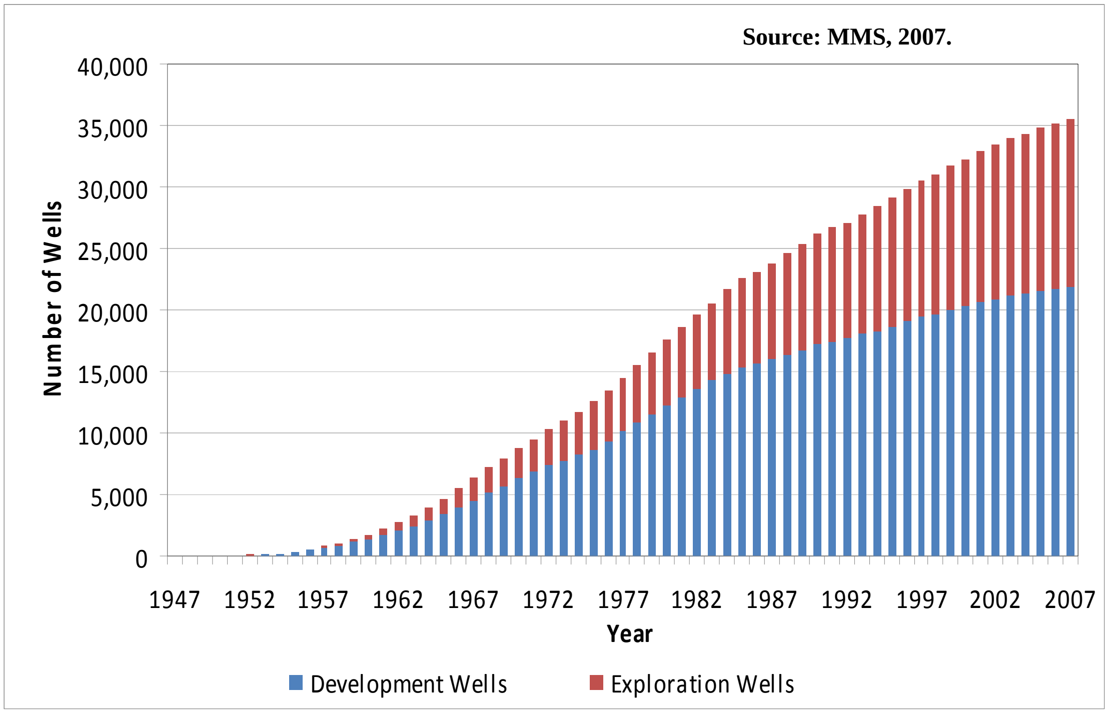


Figure A.2. Cumulative Number of Exploration and Development Wells Drilled in the Gulf of Mexico (1947-2007).

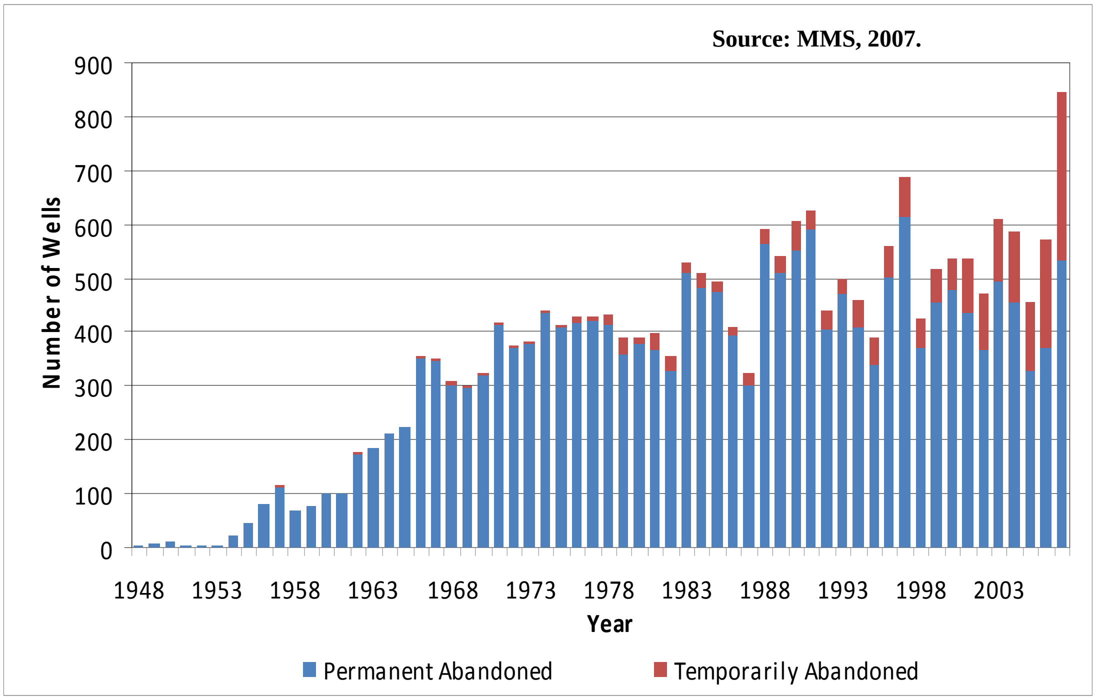


Figure A.3. Annual Number of Temporary and Permanent Well Abandonments in the Gulf of Mexico (1948-2007).

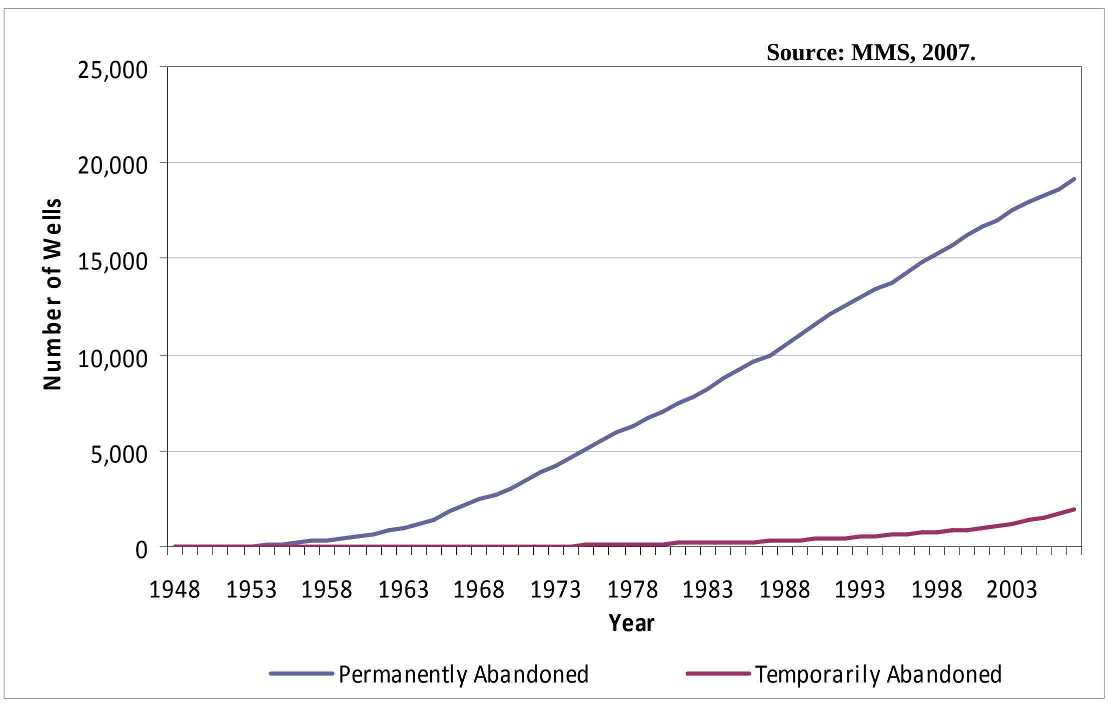


Figure A.4. Cumulative Number of Temporary and Permanent Abandoned Wells in the Gulf of Mexico (1948-2007). Temporarily Abandoned Wells Will Be Permanently Abandoned in the Future.

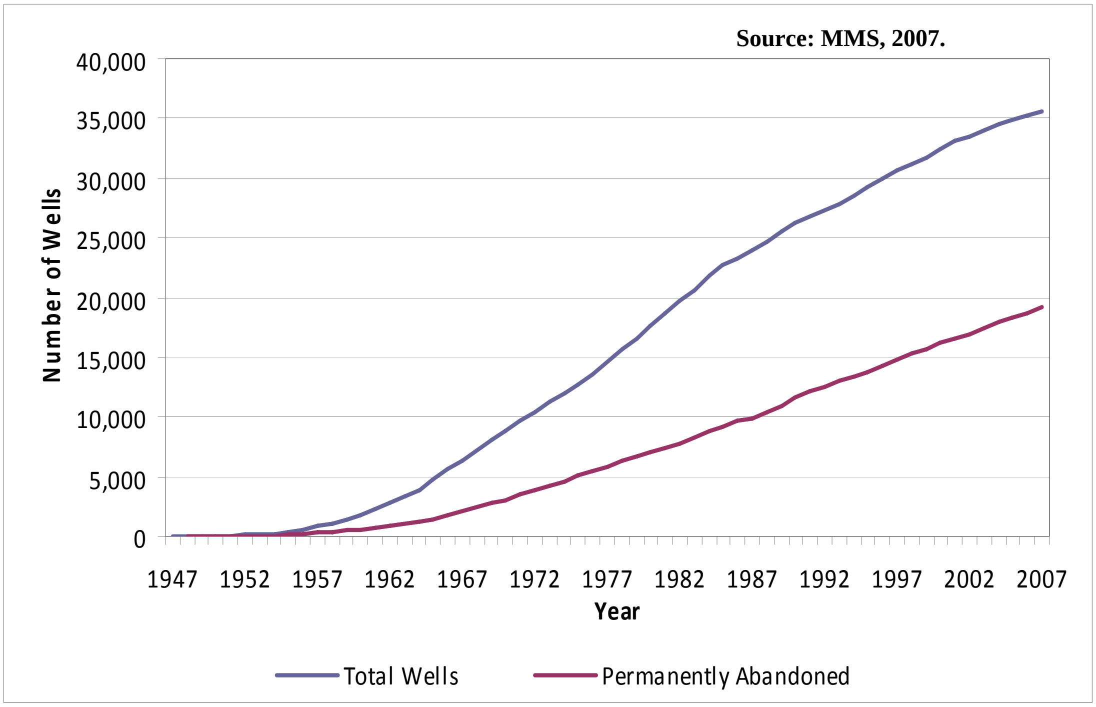


Figure A.5. Total Number of Wells (Exploration and Development) Drilled and Permanent Abandonments in the Gulf of Mexico (1947 - 2007).

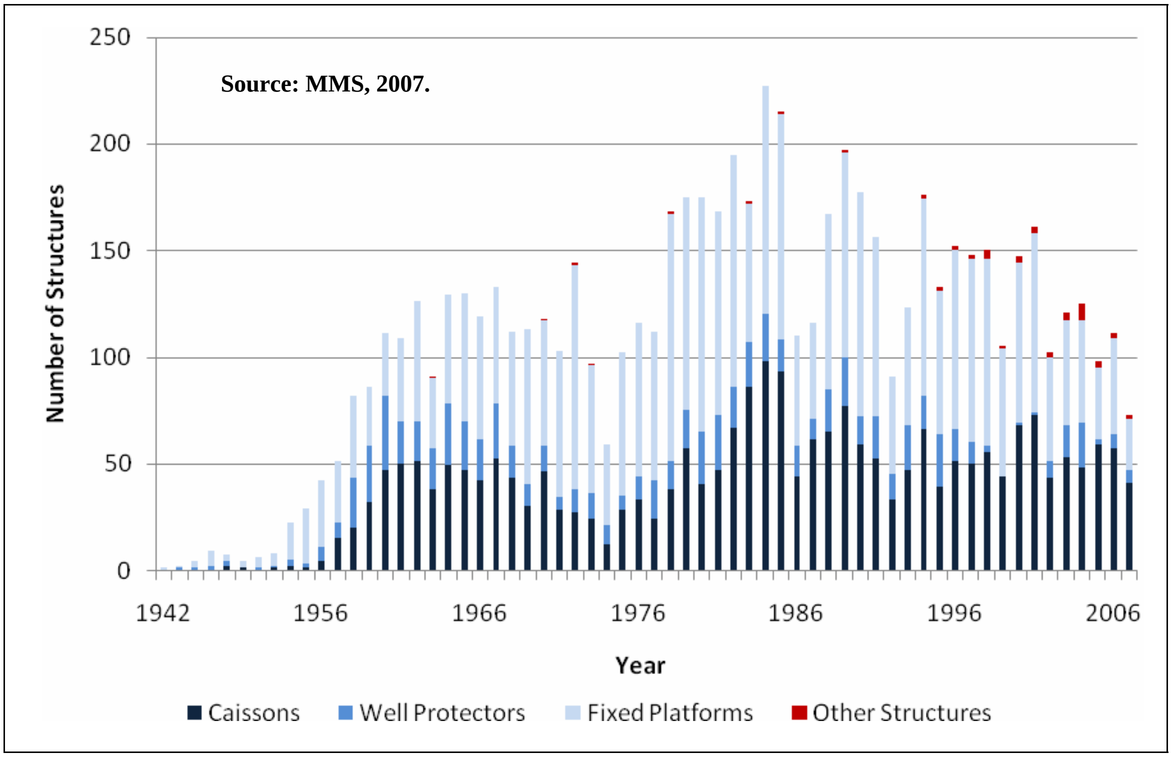


Figure A.6. Structure Installations in the Gulf of Mexico (1942 - 2007). Data for 2007 Is Not Complete Because of Delays in Reporting.

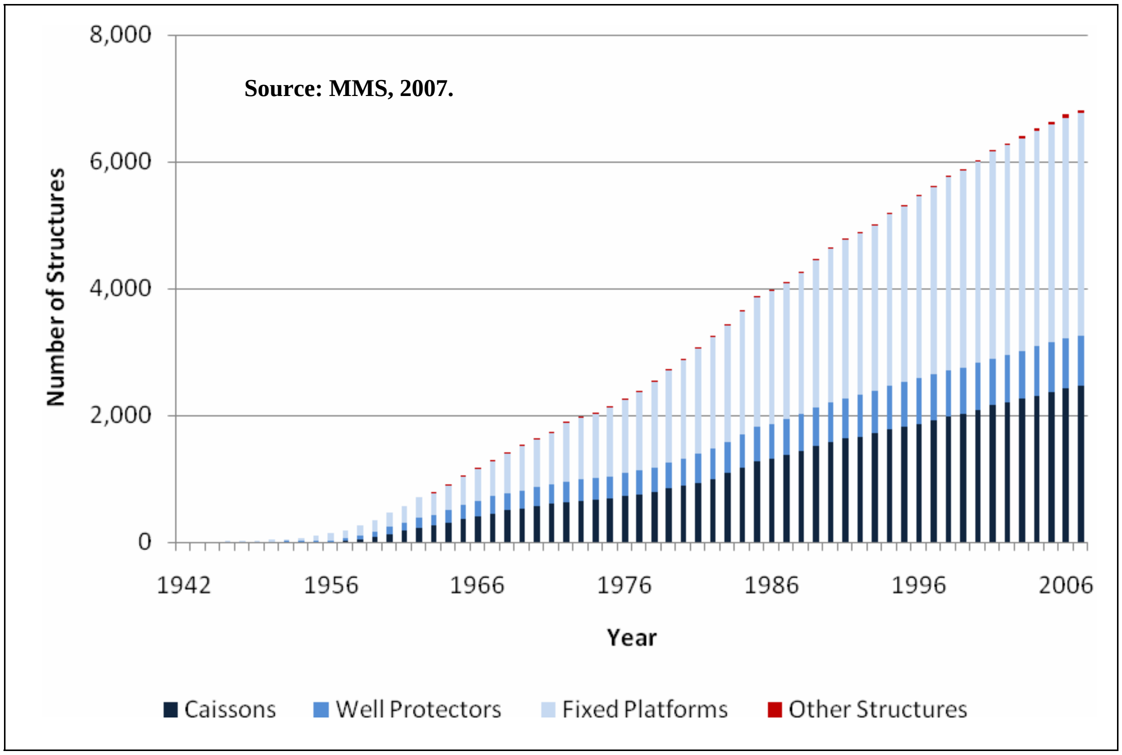


Figure A.7. Cumulative Number of Structure Installations in the Gulf of Mexico (1942-2007).

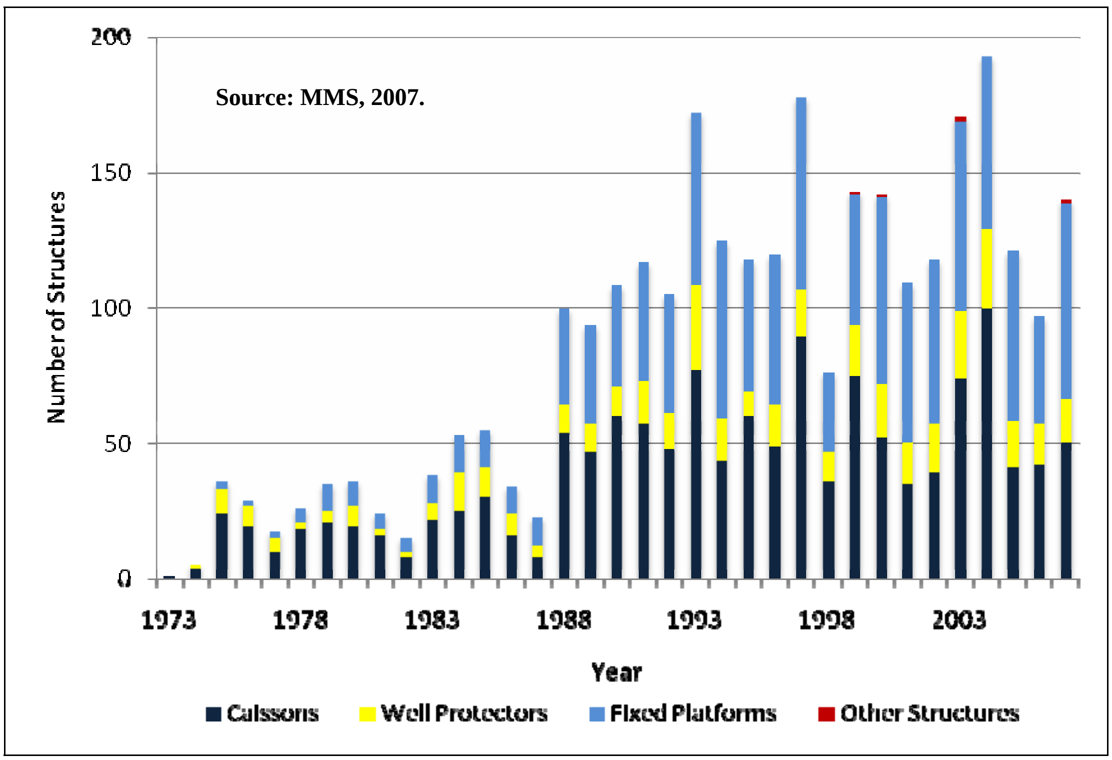


Figure A.8. Structure Removals in the Gulf of Mexico (1973-2007). Data for 2007 Is Not Complete Because of Delays in Reporting.

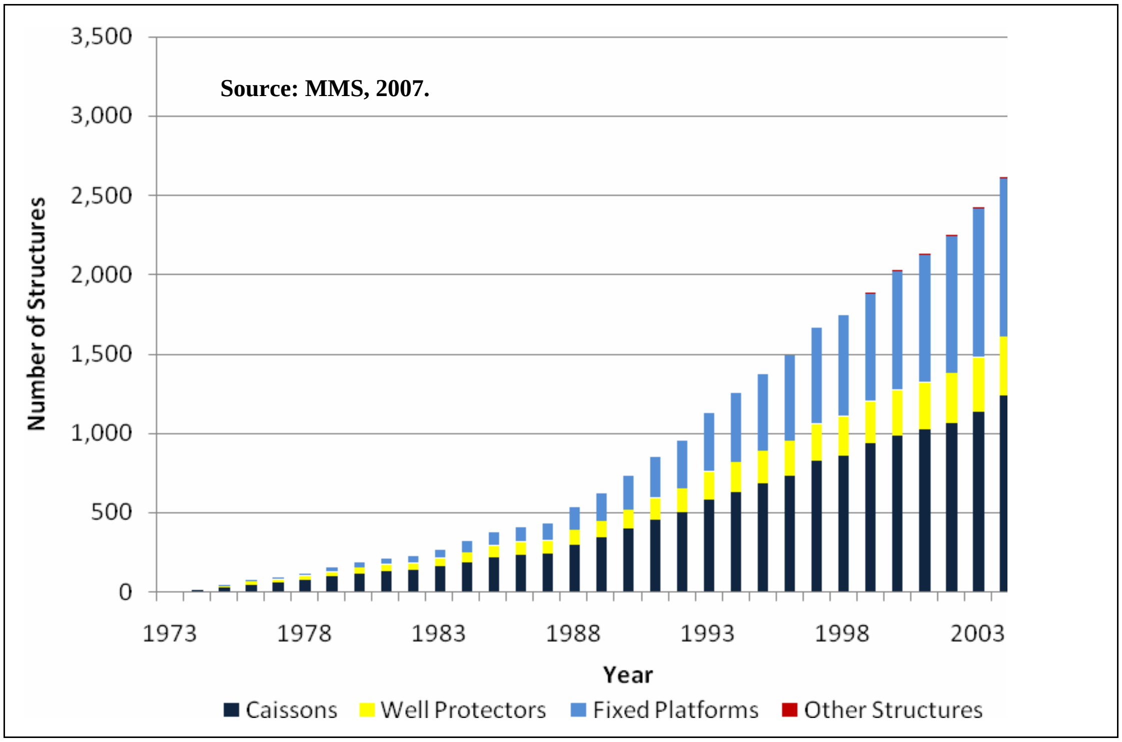


Figure A.9. Cumulative Number of Structure Removals in the Gulf of Mexico (1973-2007).

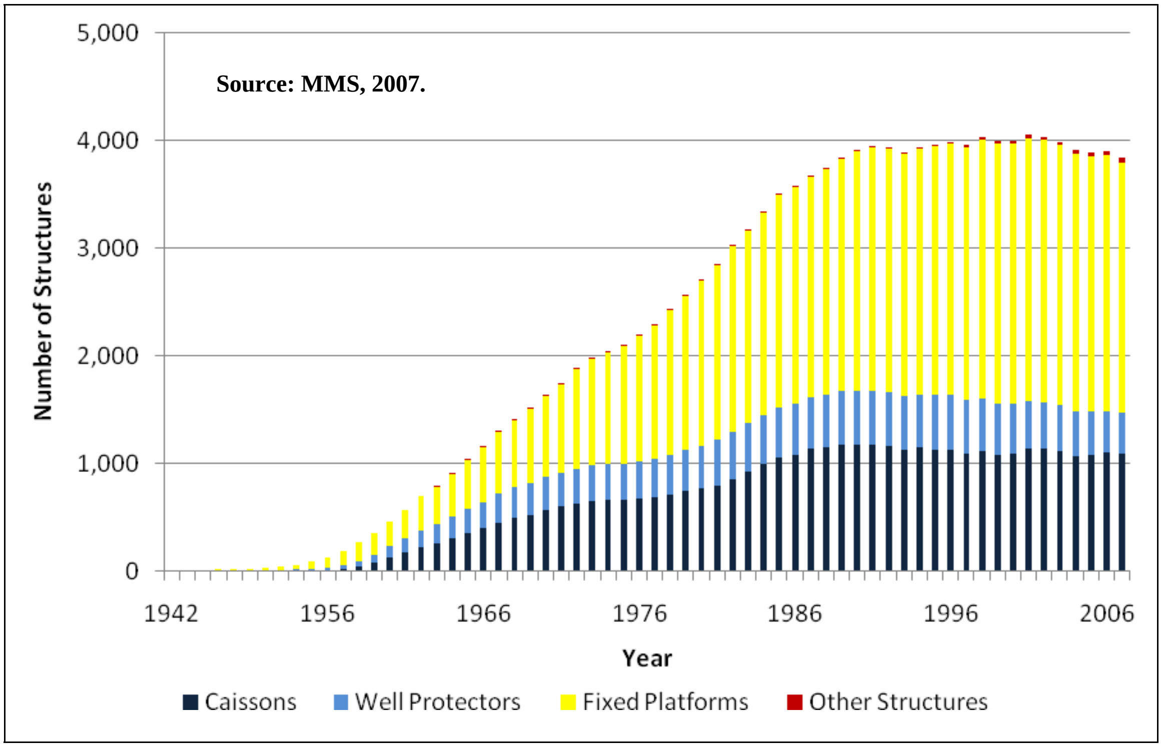


Figure A.10. Active Structures in the Gulf of Mexico (1942-2007).

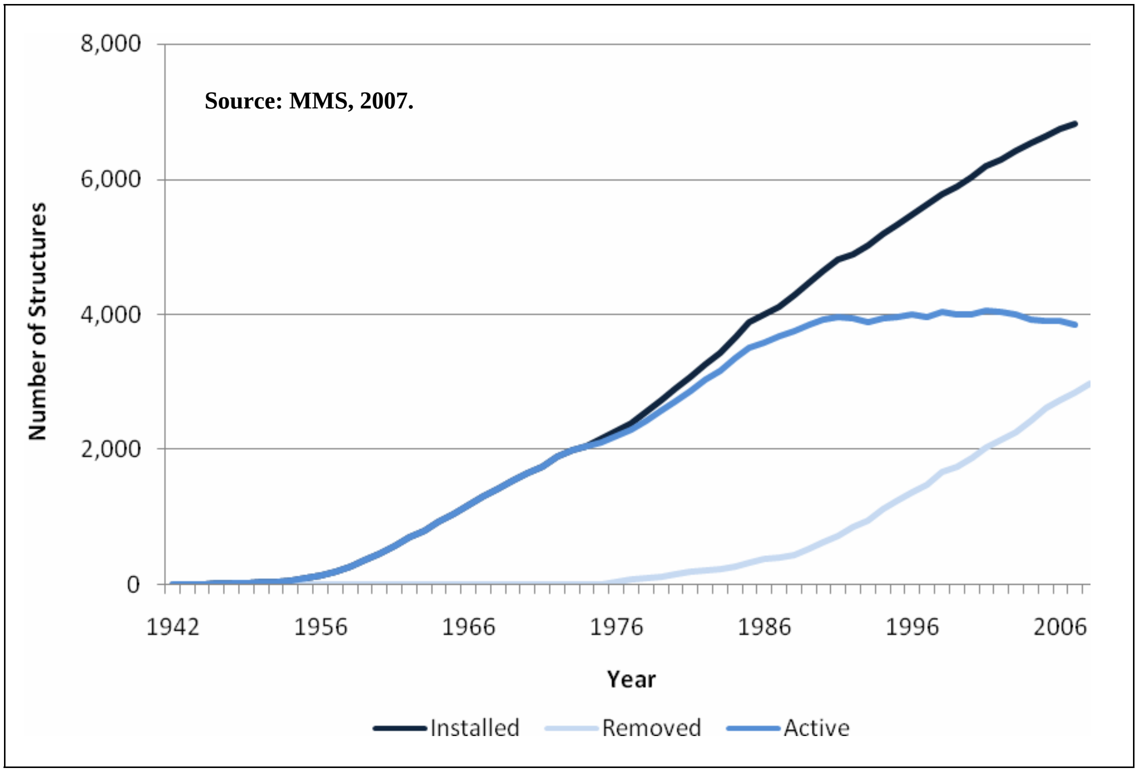


Figure A.11. Cumulative Number of Installed, Removed and Active Structures in the Gulf of Mexico (1942-2007).

APPENDIX B

CHAPTER 2 TABLE AND FIGURE

Table B.1.

Average Dismantlement, Restoration, and Abandonment Cost per Well for Offshore Properties

Average Cost per Well ($/well)	All (%)	Successful Efforts (%)	Full Cost (%)	Independent (%)	Major (%)
≤ $1,000	5.3	0	11.1	6.3	0
$1,000 - $50,000	10.5	0	22.2	12.5	0
$50,001-$300,000	42.1	50.0	33.3	37.5	66.7
$300,001-$1,000,000	42.1	50.0	33.3	43.8	33.3
≥ $1,000,000	0	0	0	0	0
	100 (19)[a]	100 (10)	100 (9)	100 (16)	100 (3)

Source: 2001 PricewaterhouseCoopers survey (Coe et al., 2001).
Footnote: (a) The number in parenthesis represents the sample size.

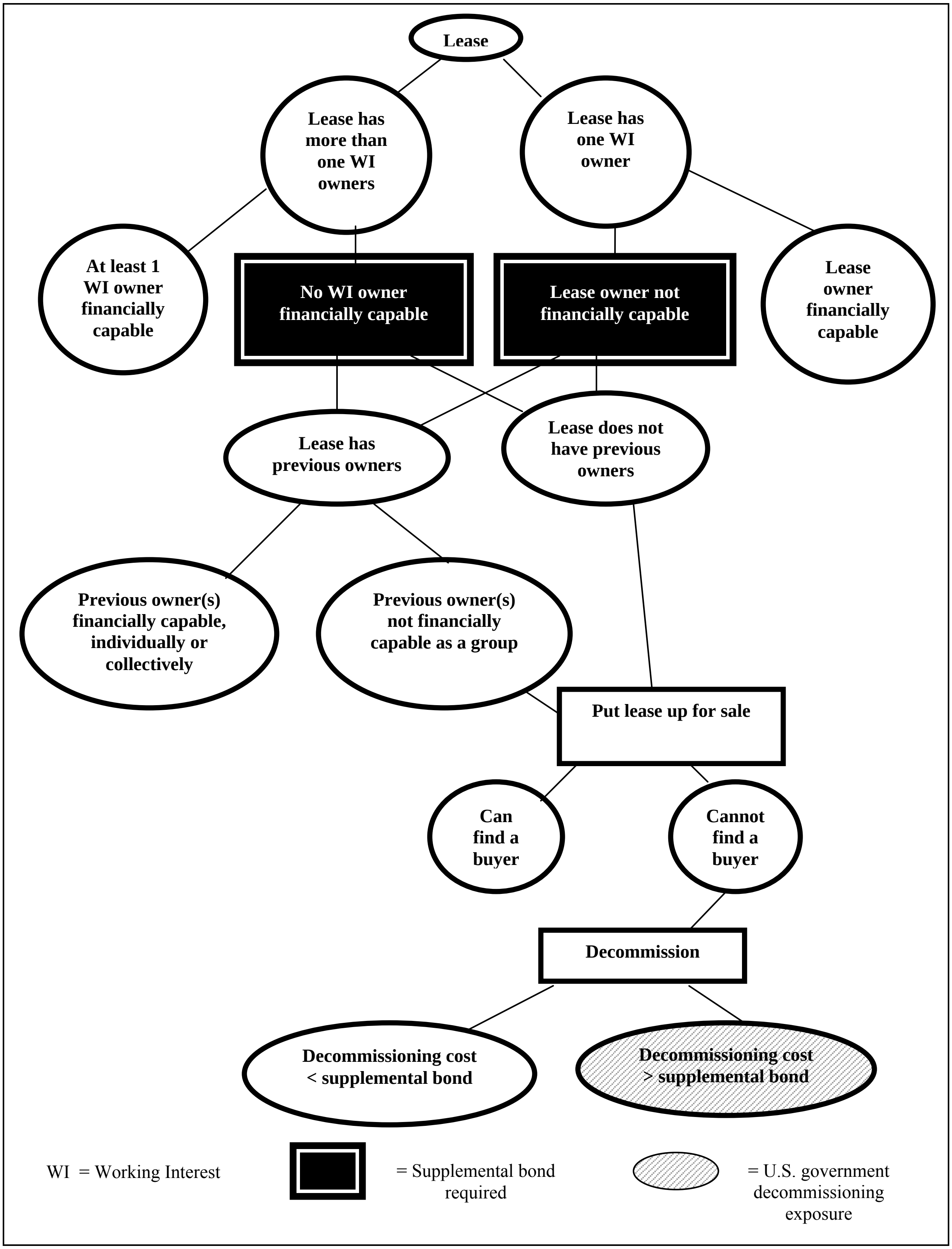


Figure B.1. Sequence of Events Required to Trigger Government Liability.

APPENDIX C

CHAPTER 3 TABLES

Table C.1.

MMS Supplemental Bonding Legacy Formula[a]

Decommissioning Stage	Water Depth (feet)	Estimated Cost[b] ($1,000)
Plug & Abandon	all	100
Structure Removal	< 150	400
	151 - 200	600
	201- 299	1,250
	> 300	2,000+
Site Clearance & Verification	< 150	300
	151- 249	400
	> 250	500

Source: MMS, 1998.

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.

(b) The P&A unit cost is per borehole, the structure removal cost is per structure, and the SC&V cost is per leasehold. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.

Table C.2.

Plugging and Abandonment Cost – Independent Operators

Year	Number of wells	Dayrate ($1,000)	Turnkey ($1,000)	Average Cost ($1,000)
2002	51	61	136	107 (12)[a]
2003	59	54	157	115 (22)
2004	193	91	155	128 (11)
2005	192	93	189	149 (16)
2006	390	237	51	167 (22)
2007	34	195	107	178 (51)
2002-2007	1,156	122	143	134(8)

Source: Kaiser and Dodson 2008.

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table C.3.

Plugging and Abandonment Cost – Majors (2005-2007)

Water Depth (ft)	Number of wells	Average Cost ($1,000)
0-100	75	1,172 (992)
101-200	27	967 (935)
201-300	13	956 (494)
All	115	1,099 (956)

Source: MMS, 2007.
Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table C.4.

Plugging and Abandonment Cost Tableau – Independents and Majors, Equal Weight Average[a], Cost Inflation = 10% per Year

Year	*p*	*C* ($1000)	*C* + 1**SD* ($1000)	*C* + 2**SD* ($1000)	*C* + 3**SD* ($1000)
2008	0	639	1,143	1,647	2,151
2009	1	703	1,257	1,812	2,366
2010	2	773	1,383	1,993	2,603
2011	3	851	1,521	2,192	2,863
2012	4	936	1,673	2,411	3,149
2013	5	1,029	1,841	2,653	3,464
2014	6	1,132	2,025	2,918	3,811
2015	7	1,245	2,227	3,210	4,192
2016	8	1,370	2,450	3,530	4,611

Footnote: (a) Risk-adjusted cost elements derived from Table C.2 and Table C.3.
To use this Table:

1) Define the time horizon in which the bonding formula will be valid. Specify the last year of the horizon in column one.
2) Go to column two and read off the corresponding value of *p*.
3) Now go to row [*p*/2]; round up for odd *p*.
4) Select column according to desired objectives, levels of uncertainty associated with estimation, and level of risk adjustment. *C* (high risk), *C*+1**SD* (moderate risk), *C*+2**SD* (low risk), *C*+3**SD* (very low risk).

Table C.5.

Removal Cost Statistics – Independent Operators

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
0-100	686 (560)[a]	1,131 (970)
101-200	1,525 (881)	2,023 (1,276)
201-300		3,468 (2,590)

Source: Kaiser, Dodson, and Foster 2008.
Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table C.6.

Removal Cost Tableau – Independent Operators, No Cost Inflation

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
μ_{IND}:		
0-100	686	1,131
101-200	1,525	2,023
201-300		3,468
$\mu_{IND} + 1*\sigma_{IND}$:		
0-100	1,246	2,101
101-200	2,406	3,299
201-300		6,058
$\mu_{IND} + 2*\sigma_{IND}$:		
0-100	1,806	3,071
101-200	3,287	4,575
201-300		8,648
$\mu_{IND} + 3*\sigma_{IND}$:		
0-100	2,366	4,041
101-200	4,168	5,851
201-300		11,238

Note: Risk-adjusted cost elements in this table are derived from Table C.5.

Table C.7.

Removal Cost Statistics – Majors

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
0-100	1,834 (382)[a]	1,922 (1,136)
101-200	2,100 (993)	2,317 (1,390)
201-300		2,712 (1,827)

Source: MMS, 2007.
Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table C.8.

Removal Cost Tableau – Majors, No Cost Inflation

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
μ_{MAJ}:		
0-100	1,834	1,922
101-200	2,100	2,317
201-300		2,712
$\mu_{MAJ} + 1{*}\sigma_{MAJ}$:		
0-100	2,216	3,058
101-200	3,093	3,707
201-300		4,339
$\mu_{MAJ} + 2{*}\sigma_{MAJ}$:		
0-100	2,598	4,194
101-200	4,086	5,097
201-300		5,966
$\mu_{MAJ} + 3{*}\sigma_{MAJ}$:		
0-100	2,980	5,330
101-200	5,079	6,487
201-300		7,593

Note: Risk-adjusted cost elements in this table are derived from Table C.7.

Table C.9.

Removal Cost Tableau – Independents and Majors, Equal Weight Average[a], No Cost Inflation

Water Depth (ft)	Caisson & Well Protector ($1,000)	Fixed Platform ($1,000)
C:		
0-100	1,260	1,527
101-200	1,813	2,470
201-300		3,090
C+ 1*SD:		
0-100	1,731	2,580
101-200	2,750	3,503
201-300		5,199
C + 2*SD:		
0-100	2,202	3,633
101-200	3,687	4,836
201-300		7,307
C + 3*SD:		
0-100	2,673	4,686
101-200	4,624	6,169
201-300		9,416

Footnote: (a) $C = (\mu_{IND} + \mu_{MAJ})/2$, $SD = (\sigma_{IND} + \sigma_{MAJ})/2$ obtained from Table C.6 and Table C.8.

Table C.10.

Site Clearance and Verification Cost Tableau – Independents and Majors, No Cost Inflation

Structure Type	C ($1,000)	C + 1*SD ($1,000)	C + 2*SD ($1,000)	C + 3*SD ($1,000)
Caisson	16	26	36	46
Well Protector & Fixed Platform	43	67	91	115

Source: Kaiser and Martin 2008.

Table C.11.

Supplemental Bonding Tableau[a] (2008-2013) – High Risk (Average Cost)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	773	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	1,260	1,527
	101 - 200	1,813	2,470
	201- 300		3,090
		CAIS	WP & FP
Site Clearance & Verification	all	16	43

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) Plug and abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.
(c) CAIS = caisson, WP = well protector, FP = fixed platform.

Table C.12.

Supplemental Bonding Tableau[a] (2008-2013) – Moderate Risk (Average Cost + 1*Standard Deviation)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	1,383	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	1,731	2,580
	101 - 200	2,750	3,503
	201- 300		5,199
		CAIS	WP & FP
Site Clearance & Verification	all	26	67

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) Plug and abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.
(c) CAIS = caisson, WP = well protector, FP = fixed platform.

Table C.13.

Supplemental Bonding Tableau[a] (2008-2013) – Low Risk (Average Cost + 2*Standard Deviation)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	1,993	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	2,200	3,633
	101 - 200	3,687	4,836
	201- 300		7,307
		CAIS	WP & FP
Site Clearance & Verification	all	36	91

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) Plug and abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.
(c) CAIS = caisson, WP = well protector, FP = fixed platform.

Table C.14.

Risk-Adjusted Supplemental Bonding Tableau[a] (2008-2013) – Very Low Risk (Average Cost + 3*Standard Deviation)

Decommissioning Stage	Water Depth (ft)	Estimated Cost[b] ($1,000)	
Plug & Abandon	all	2,603	
		CAIS & WP[c]	FP
Structure Removal	0 - 100	2,673	4,686
	101 - 200	4,624	6,169
	201- 300		8,416
		CAIS	WP & FP
Site Clearance & Verification	all	46	115

Footnote: (a) The MMS reserves the right to adjust the cost estimates when available information shows that the numbers are not accurate.
(b) Plug and abandonment unit cost is per borehole, removal cost is per structure type, and site clearance and verification cost is per structure type. Total lease liability is computed by summing the unit cost elements for the number of wells and structures per leasehold.
(c) CAIS = caisson, WP = well protector, FP = fixed platform.

Table C.15.

Supplement Bond Requirements Under Various Risk-Adjustments – Example 1

	Risk-Adjusted Cost Level ($ million)			
Stage	*C*	*C* + 1**SD*	*C* + 2**SD*	*C* + 3**SD*
P&A	20.10	35.96	51.82	67.68
REM	6.83	10.35	13.87	17.39
SC&V	0.161	0.253	0.345	0.437
Total	28.39	46.56	66.04	85.51

Table C.16.

Supplement Bond Requirements Under Various Risk-Adjustments – Example 2

	Risk-Adjusted Cost Level ($ million)			
Stage	*C*	*C* + 1**SD*	*C* + 2**SD*	*C* + 3**SD*
P&A	23.96	42.87	61.78	80.69
REM	10.38	15.26	20.73	26.21
SC&V	0.134	0.212	0.290	0.360
Total	34.47	58.34	82.80	107.26

APPENDIX D

CHAPTER 4 TABLES AND FIGURES

Table D.1.

Plug and Abandonment Statistics, 2002-2005

Parameter (unit)	2002			2003			2004			2005		
	DR	TK	ALL	DR	TK	ALL	DR	TK	ALL	DR	TK	ALL
Avg_cost_well ($1000/well)	61	136	107	54	157	115	91	155	128	93	189	149
SD_Acw	8	17	12	13	34	22	14	15	11	20	24	16
Avg_cost_day ($1000/day)	5.6	15.8	11.8	8.5	22.3	16.5	13	19.4	16.8	10	22.2	17.2
SD_Acd	0.7	1.7	1.3	1.4	4.7	2.9	1.9	1.2	1.1	1.6	1.2	1.3
Avg_days_well (days/well)	12.7	10	11	7	8.5	8.1	8.2	8.4	8.3	11.2	8.3	9.5
SD_Adw	2	1	1	1.5	1.4	1	1.2	0.8	0.7	2.1	0.8	1
Number_jobs	20	31	51	24	35	59	22	29	51	18	25	43
Number_wells	24	104	128	59	152	255	55	138	193	44	148	192
Number_wells/Number_job	1.2	3.4	2.5	2.5	4.3	4.3	2.5	4.7	3.9	2.4	5.9	4.1

Footnote: DR= dayrate contracts, TK = turnkey contracts, ALL = dayrate and turnkey contracts.

Table D.2.

Plug and Abandonment Statistics, 2006-2007

Parameter (unit)	2006			2007		
	DR	TK	ALL	DR	TK	ALL
Avg_cost_well ($1000/well)	237	51	167	195	107	178
SD_Acw	27	12	22	62	-	51
Avg_cost_day ($1000/day)	28	23.2	26.1	28	11	24.5
SD_Acd	3.6	30	2.5	12.7	-	10.5
Avg_days_well (days/well)	10.2	2.4	7.3	8.5	10	8.8
SD_Adw	1	0.8	0.9	2.5	-	2
Number_jobs	31	19	50	4	1	5
Number_wells	94	296	390	22	8	34
Number_wells/Number_job	3	15.6	7.8	5.5	8	6.8

Footnote: DR= dayrate contracts, TK = turnkey contracts, ALL = dayrate and turnkey contracts.

Table D.3.

Composite Average Plug and Abandonment Statistics, 2002-2007

Parameter (unit)	DR	TK	ALL
Avg_cost_well ($1000/well)	122	143	134
SD_Acw	11	11	8
Avg_cost_day ($1000/day)	15	20.3	17.9
SD_Acd	1.4	1.3	1
Avg_days_well (days/well)	9.8	8	8.8
SD_Adw	0.7	0.5	0.4
Number_jobs	116	140	256
Number_wells	300	856	1156
Number_wells/Number_job	2.6	6.1	4.5

Footnote: DR= dayrate contracts, TK = turnkey contracts, ALL = dayrate and turnkey contracts.

Table D.4.

Regression Model Results – I

Parameter	$TC = \alpha_0 + \alpha_1 NW^a$					
	Dayrate		Turnkey		All	
	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		59.5 (1.5)[b]		173.2 (3.0)		149.6 (4.4)
α_1	102.6 (13.5)	91.6 (8.8)	65.7 (14.3)	55.9 (10.1)	69.3 (18.9)	59.0 (13.9)
R^2	0.61	0.40	0.59	0.42	0.58	0.43
n	116	116	140	140	256	256

Footnote: (a) TC = Total Cost; NW = Number of Wells.

(b) The t- statistics of the regression models are presented in parenthesis.

Table D.5.

Regression Model Results – II

Parameter	$TC = \alpha_0 + \alpha_1 ND + \alpha_2 NW$ [a]					
	Dayrate		Turnkey		All	
	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		51.7 (1.4)[b]		-65.2 (-1.9)		-10.6 (*)
α_1	5.5 (3.9)	5.4 (3.9)	18.4 (18.5)	19.2 (17.9)	12.6 (15.7)	12.7 (14.6)
α_2	56.8 (4.2)	48.1 (3.2)	9.6 (24)	10.8 (2.8)	24.4 (6.3)	24.6 (6.3)
R^2	0.65	0.46	0.88	0.83	0.79	0.69
n	116	116	140	140	256	256

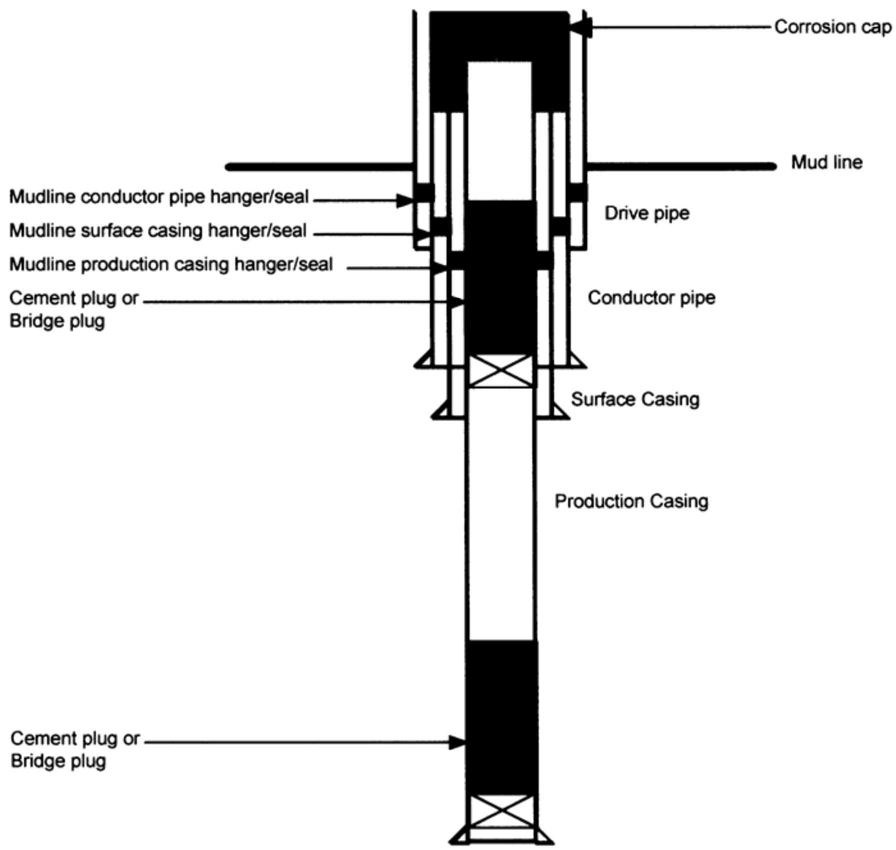
Footnote: (a) TC = Total Cost; ND = Number of days; NW = Number of Wells.

(b) The t- statistics of the regression models are presented in parenthesis. (*) denotes t statistics < 1.

Table D.6.

Impact of Scale on Average Plug and Abandonment Cost

Contract Type	Parameter (unit)	[1] well	[2-4] wells	[5-9] wells	[10-15] wells	[>15] wells
ALL	Avg_cost_well ($1000/well)	152	154	88	64	48
	SD_Acw	14	14	12	11	11
	Number_jobs	116	77	36	15	12
	Number_wells	116	236	289	181	334
DR	Avg_cost_well ($1000/well)	116	141	79	103	96
	SD_Acw	121	132	50	51	-
	Number_jobs	63	42	8	2	1
	Number_wells	63	135	59	26	17
TK	Avg_cost_well ($1000/well)	194	169	90	58	44
	SD_Acw	168	101	74	41	40
	Number_jobs	53	35	28	13	11
	Number_wells	53	101	230	155	317



Source: MMS, 2000.

Figure D.1. Temporary Abandonment Well Schematic.

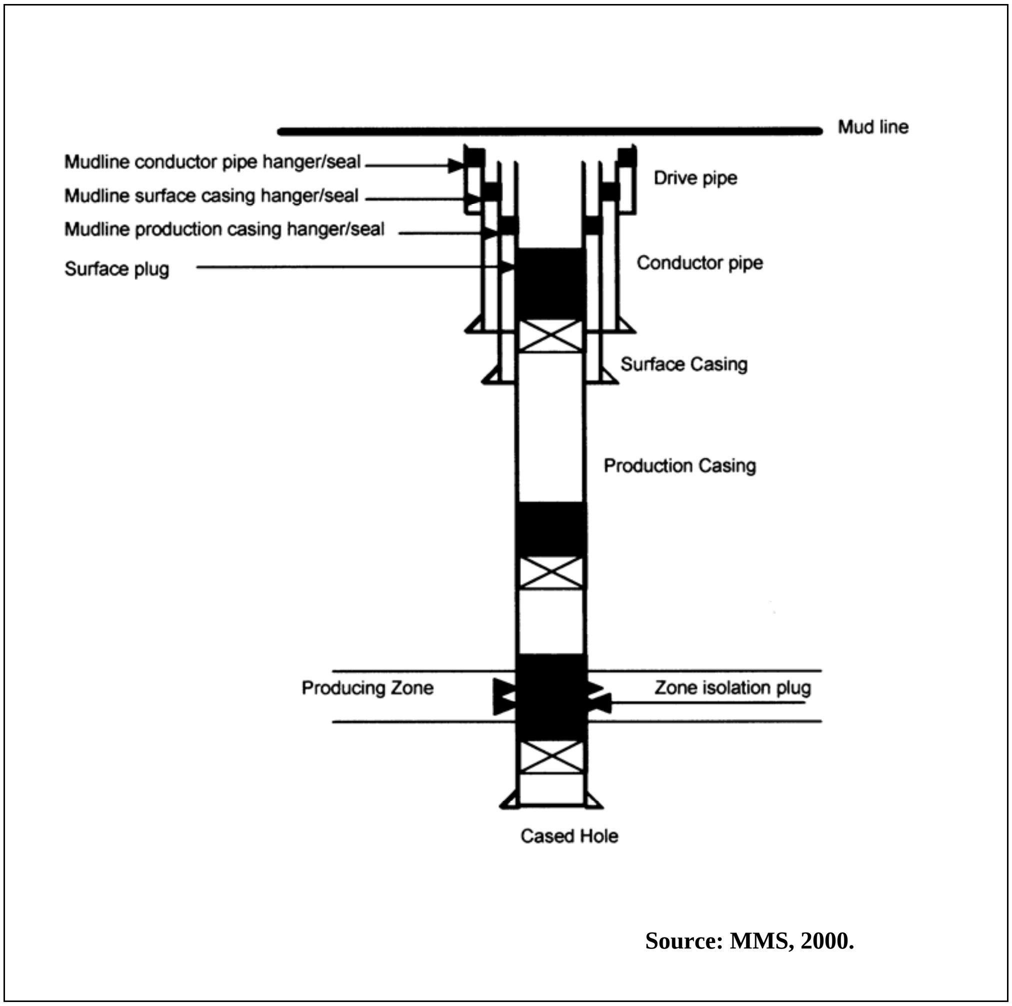


Figure D.2. Permanent Abandonment Well Schematic.

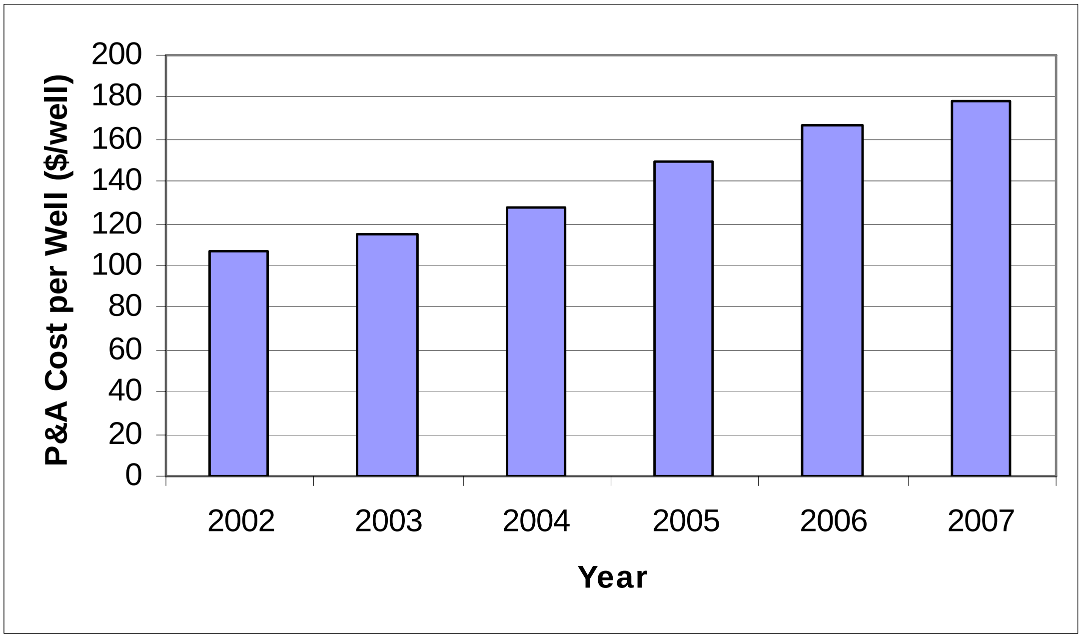


Figure D.3. Average P&A Aggregate Cost per Wellbore, 2002-2007.

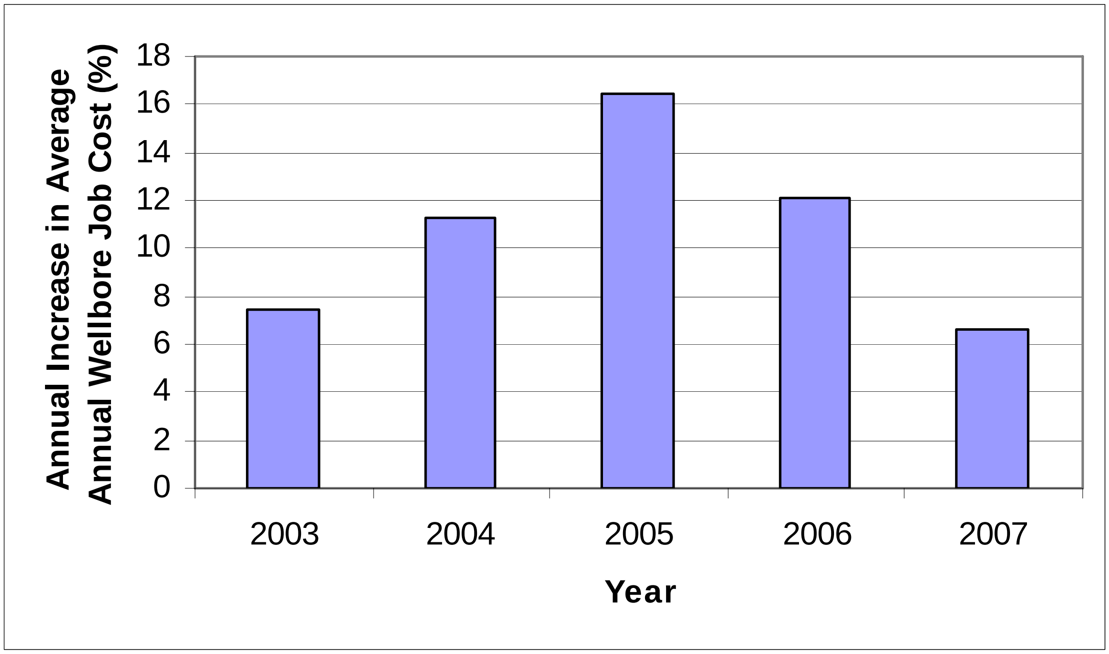


Figure D.4. Annual Increase in Average Wellbore Cost (%).

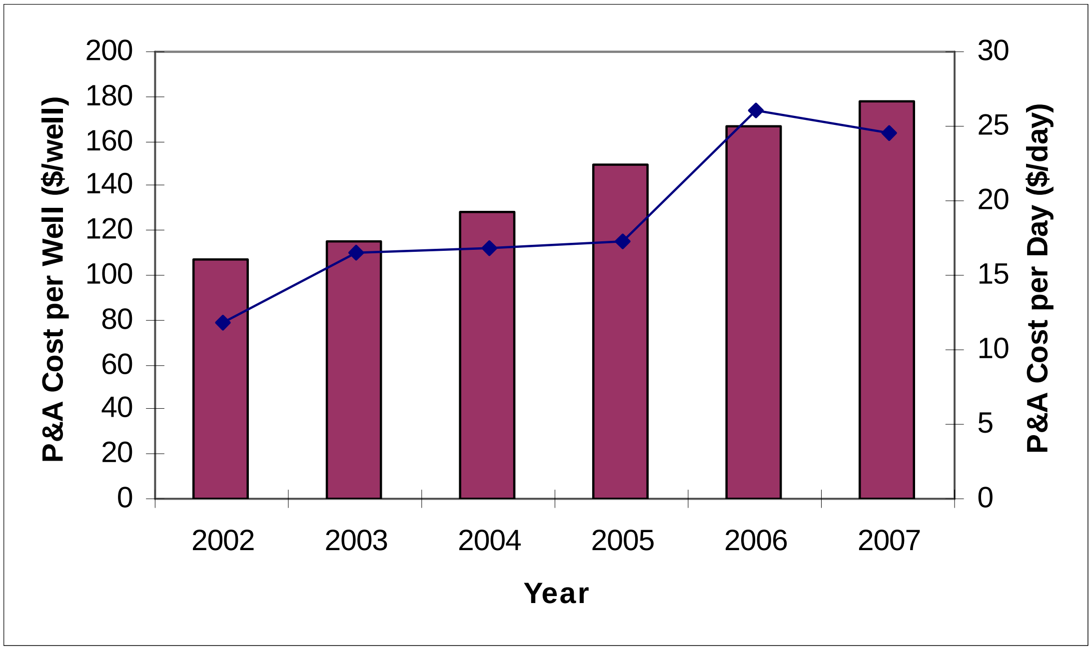


Figure D.5. Average P&A Cost per Well ($/well) and Equivalent P&A Cost per Day of Service.

APPENDIX E

CHAPTER 5 TABLES AND FIGURES

Table E.1.

Total Project Cost of the Sample Set, 2003-2008 ($ million)

Water Depth (ft)	Caisson ($ million)	Well Protector ($ million)	Fixed Platform ($ million)	All ($ million)
0-100	16.0	6.2	28.8	51.0
101-200	11.4	-	60.7	72.1
201-300	-	-	54.6	54.6
All	27.4	6.2	144.1	177.7

Table E.2.

Average Preparation Cost – Fixed Platforms

Water Depth (ft)	Number of Structures	Cost ($1,000)
0-100	12	79 (91) [a]
101-200	13	90 (59)
201-300	10	242 (355)
All	35	130 (206)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.3.

Average Pipeline Abandonment Cost – All Structures

Water Depth (ft)	Number of Structures	Cost ($1,000)
0-100	16	187 (256)[a]
101-200	12	298 (269)
201-300	3	674 (737)
All	31	272 (332)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.4.

Number of Removed Structures

Water Depth (ft)	Caisson	Well Protector	Fixed Platform	All
0-100	29	15	28	72
101-200	9	-	32	41
201-300	-	-	18	18
> 300	-	-	2	2
All	38	15	80	133

Table E.5.

Average Structure Removal Cost

Water Depth (ft)	Caisson ($1,000)	Well Protector ($1,000)	Fixed Platform ($1,000)	All ($1,000)
0-100	499 (304)[a]	393 (190)	865 (623)	619 (492)
101-200	1,227 (612)	-	1,634 (948)	1,545 (884)
201-300	-	-	2,579 (1,498)	2,579 (1,498)
All	672 (501)	393 (190)	1,576 (1,200)	1,150 (1,086)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.6.

Disposition of Fixed Platforms

Water Depth (ft)	Onshore	Reef	Percentage Reefed (%)
0-100	19	9	32
101-200	5	27	84
201-300	1	17	94
> 300	1	1	100
All	26	54	68

Table E.7.

Average Cost of All Fixed Platform Removals by Disposition

Water Depth (ft)	Onshore ($1,000)	Reef ($1,000)	All ($1,000)
0-100	969	682	865
101-200	1,363	1,765	1,669
201-300	1,311	2,876	2,789
> 300	1,923	3,718	2,821
All	1,152	1,995	1,721

Table E.8.

Average Removal Cost of Fixed Platforms by Number of Piles

Water Depth (ft)	3-Pile ($1,000)	4-Pile ($1,000)	6-8 Pile ($1,000)	8+ Pile ($1,000)	All ($1,000)
0-100	654 (322)[a]	966 (605)	986 (833)	2,065 (-)	976 (625)
101-200	1,018 (191)	1,540 (1,035)	1,517 (700)	2,579 (1,498)	1,614 (955)
201-300	1,670 (214)	3,778 (1,551)	2,718 (1,351)	-	2,721 (1,411)
All	1,215 (506)	1,663 (1,364)	1,908 (1,176)	2,563 (911)	1,709 (1,209)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.9.

Average Removal Cost of Caissons by Foundation Type

Water Depth (ft)	Monopile ($1,000)	Skirt Piles ($1,000)	All ($1,000)
0-100	498 (321)[a]	463 (238)	484 (286)
101-200	1,515 (772)	871 (145)	1,113 (542)
All	659 (545)	590 (286)	628 (441)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.10.

Number of Fixed Platforms Removed by Year, 2003-2008

Water Depth (ft)	2003	2004	2005	2006	2007	2008
0-100	6	3	8	5	5	1
101-200	8	0	4	5	13	2
201-300	1	1	1	4	10	1
> 300	0	0	0	1	1	0
All	15	4	13	15	29	4

Table E.11.

Average Removal Cost of Fixed Platforms by Year, 2003-2008

Water Depth (ft)	2003 ($1,000)	2004 ($1,000)	2005 ($1,000)	2006 ($1,000)	2007 ($1,000)	2008 ($1,000)
0-100	578 (373)[a]	1,406 (573)	716 (373)	1,496 (809)	453 (168)	1,050 (-)
101-200	1,681 (1,001)	-	1,650 (1,001)	1,428 (726)	1,542 (1,191)	2,521 (1,300)
201-300	1,810 (-)	3,293 (-)	4,827 (-)	1,832 (821)	2,747 (1,770)	1,687 (-)
> 300	-	-	-	1,736 (-)	3,718 (-)	-
All	1,249 (911)	1,878 (1,053)	1,320 (1,572)	1,579 (634)	1,845 (1,605)	1,945 (738)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.12.

Total Removal Cost by Structure Type

Water Depth (ft)	Caisson & Well Protector[a] ($1,000)	Fixed Platform[b] ($1,000)
0-100	686 (560)[c]	1,131 (970)
101-200	1,525 (881)	2,023 (1,276)
201-300	-	3,468 (2,590)

Footnote: (a) Caisson and well protector category cost is based on pipeline abandonment and removal operations.
(b) Fixed platform cost is based on preparation, pipeline abandonment, and removal operations.
(c) Standard deviation of the category averages are presented in parenthesis.

Table E.13.

Average Deck Weight to Jacket Weight Ratio

Water Depth (ft)	Caisson	Well Protector	Fixed Platform	All
0-100	0.36 (-)[a]	0.50 (0.38)	1.25 (0.98)	1.12 (0.95)
101-200	0.87 (0.46)	-	0.92 (0.52)	0.91 (0.51)
201-300	-	-	0.66 (0.39)	0.66 (0.39)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.14.

Average Removal Cost per Ton

Water Depth (ft)	Caisson ($1,000/ton)	Well Protector ($1,000/ton)	Fixed Platform ($1,000/ton)	All ($1,000/ton)
0-100	9.5 (-)	2.3 (1.5)	1.5 (0.7)	2.0 (2.0)
101-200	6.6 (3.7)	-	2.3 (2.2)	2.8 (2.7)
201-300	-	-	2.3 (1.5)	2.3 (1.5)
> 300	-	-	1.7 (0.8)	1.7 (0.8)
All	7.6 (3.1)	2.3 (1.5)	1.7	2.3 (2.1)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.15.

Average Duration of Preparation, Pipeline Abandonment, and Removal Operations – Fixed Platforms

Water Depth (ft) (ft)	Preparation (days)	Pipeline Abandonment (days)	Removal (days)
0-100	7.5 (3.0)[a]	6.3 (3.0)	6.9 (6.3)
101-200	9.1 (4.7)	5.5 (3.3)	14.1 (10.9)
201-300	9.7 (5.4)	6.3 (6.7)	24.2 (11.4)
> 300	9.3 (2.9)	-	32.0 (12.7)
All	8.6 (5.2)	5.9 (3.5)	12.1 (11.1)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.16.

Average Structure Installation Cost

Water Depth (ft)	Caisson ($1,000)	Well Protector ($1,000)	Fixed Platform ($1,000)	All ($1,000)
0-100	534 (-)[a]	986 (205)	1,009 (482)	909 (419)
101-200	833 (-)	1,825 (1,148)	1,675 (987)	1,619 (943)
201-300	-	-	2,809 (617)	2,809 (617)
All	633 (212)	1,489 (938)	1,501 (879)	1,368 (858)

Footnote: (a) Standard deviation of the category averages are presented in parenthesis.

Table E.17.

Single Variable Removal Cost Regression Models

Removal Cost[a] ($1,000) = $\alpha\, WD$ (ft)			
Parameter	Caisson	Well Protector	Fixed Platform
α	8.2 (15.1)[b]	7.1 (9.6)	9.4 (10.5)
n	35	10	57
R^2	0.84	0.80	0.64

Footnote: (a) Removal cost reported in $1,000. *WD* = water depth (ft).
(b) t-statistics reported in parenthesis; (*) denotes t-statistic < 1.

Table E.18.

Multivariable Removal Cost Regression Models

Parameter	Removal Cost[a] ($1,000) = $\alpha_1 WD$ (ft) + $\alpha_2 WGT$ (ton) + $\alpha_3 NP$ + $\alpha_4 DUR$ (days)				
	Well Protector		Fixed Platform		
	Model I	Model II	Model I	Model II	Model III
α_1	1.7 (*)[b]	1.6 (1.3)	3.3 (3.3)	1.6 (1.6)	1.8 (2.5)
α_2				0.5 (4.0)	0.0007 (11.4)
α_3		-112.1 (-5.5)	-41.0 (-1.9)		
α_4	68.3 (1.8)	140.5 (7.0)	71.5 (8.2)	41.3 (5.0)	
n	8	8	57	36	43
R^2	0.76	0.79	0.83	0.87	0.93

Footnote: (a) Removal cost reported in $1,000. *WD* = water depth (ft), *WGT* = total weight (tons),
NP = number of piles (#), *DUR* = duration (days).
(b) t-statistics reported in parenthesis; (*) denotes t-statistic < 1.

Source: Kaiser, 2006b.

Figure E.1. Single-well Caisson Structure.

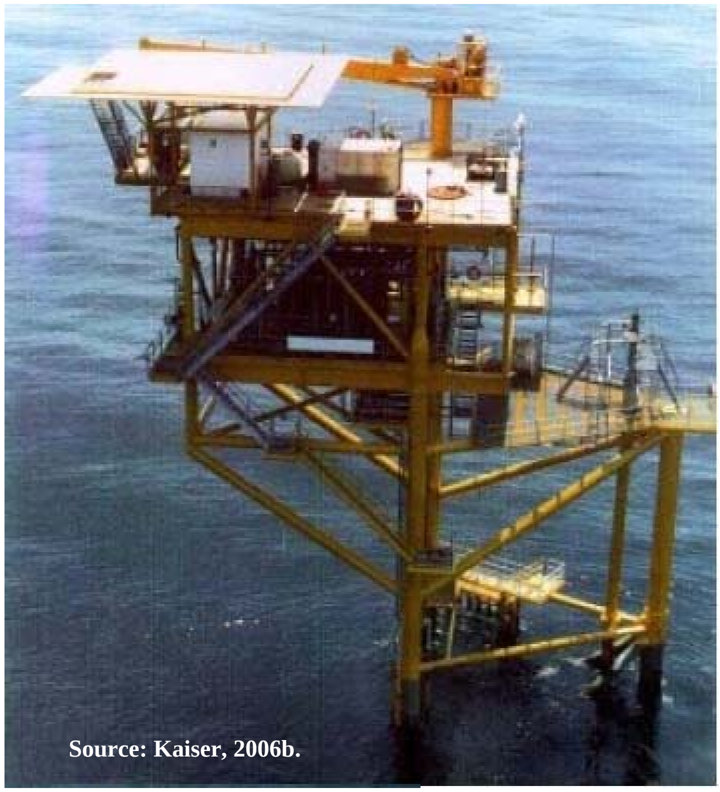
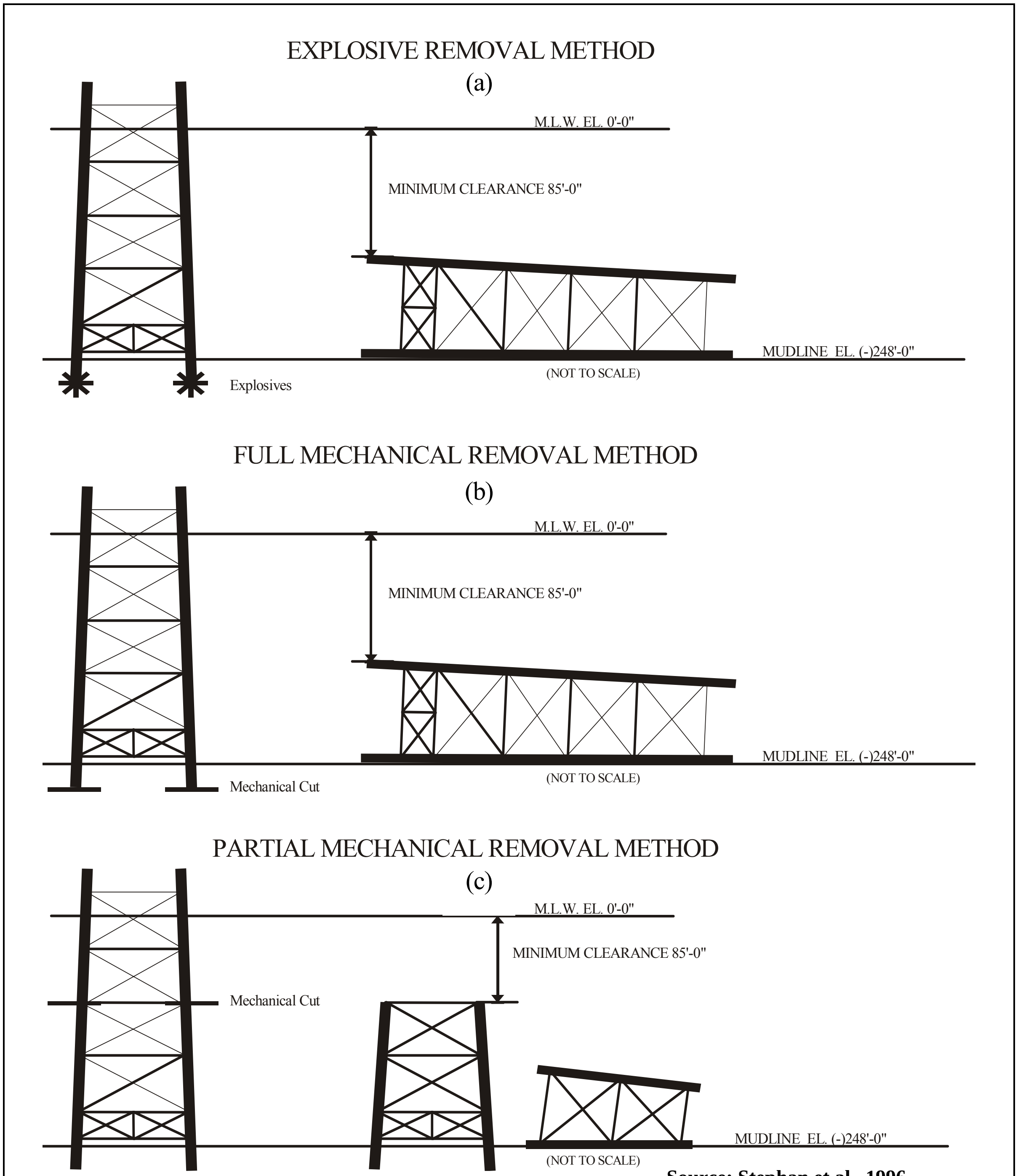


Figure E.2. Well Protector Structure.

Figure E.3. Fixed Platform Structure.



Source: Stephan et al., 1996.

Figure E.4. Platform Removal Methods.

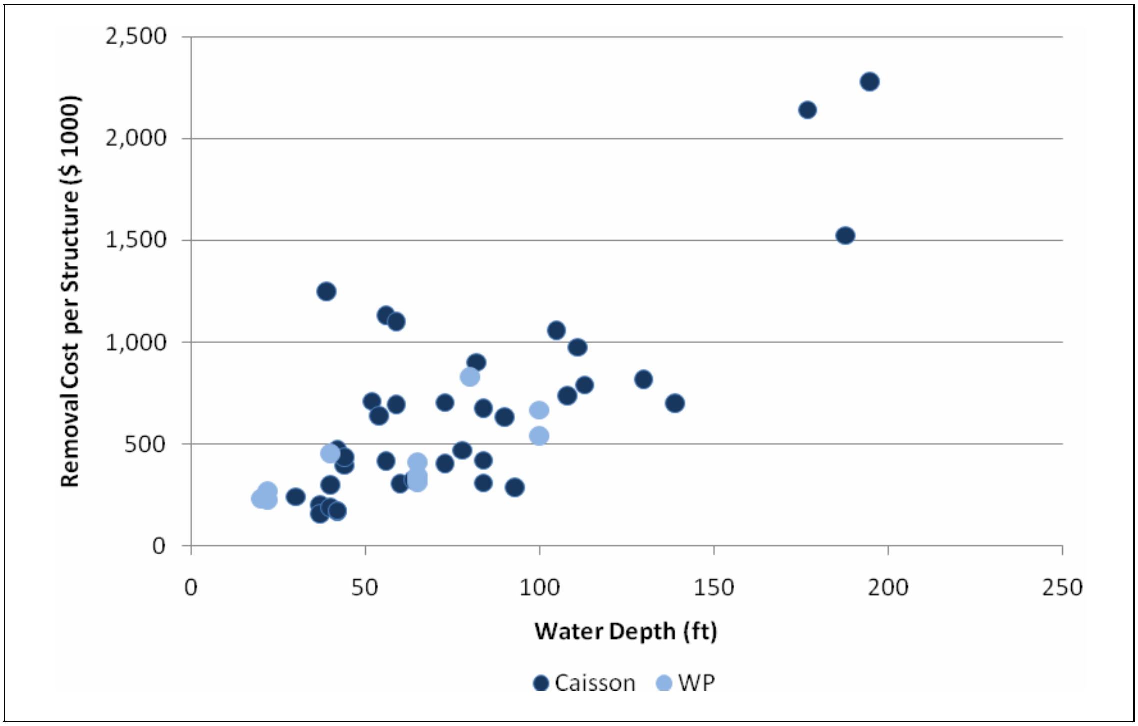


Figure E.5. Average Removal Cost of Caissons and Well Protectors.

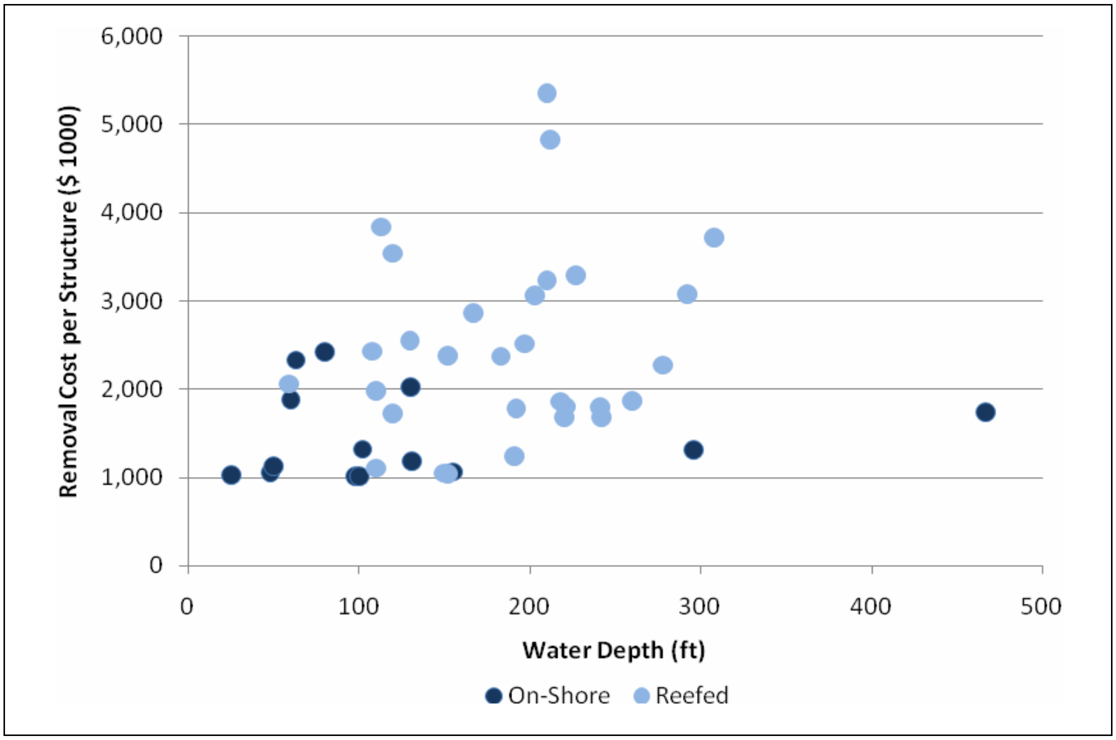


Figure E.6. Average Removal Cost of Fixed Platforms.

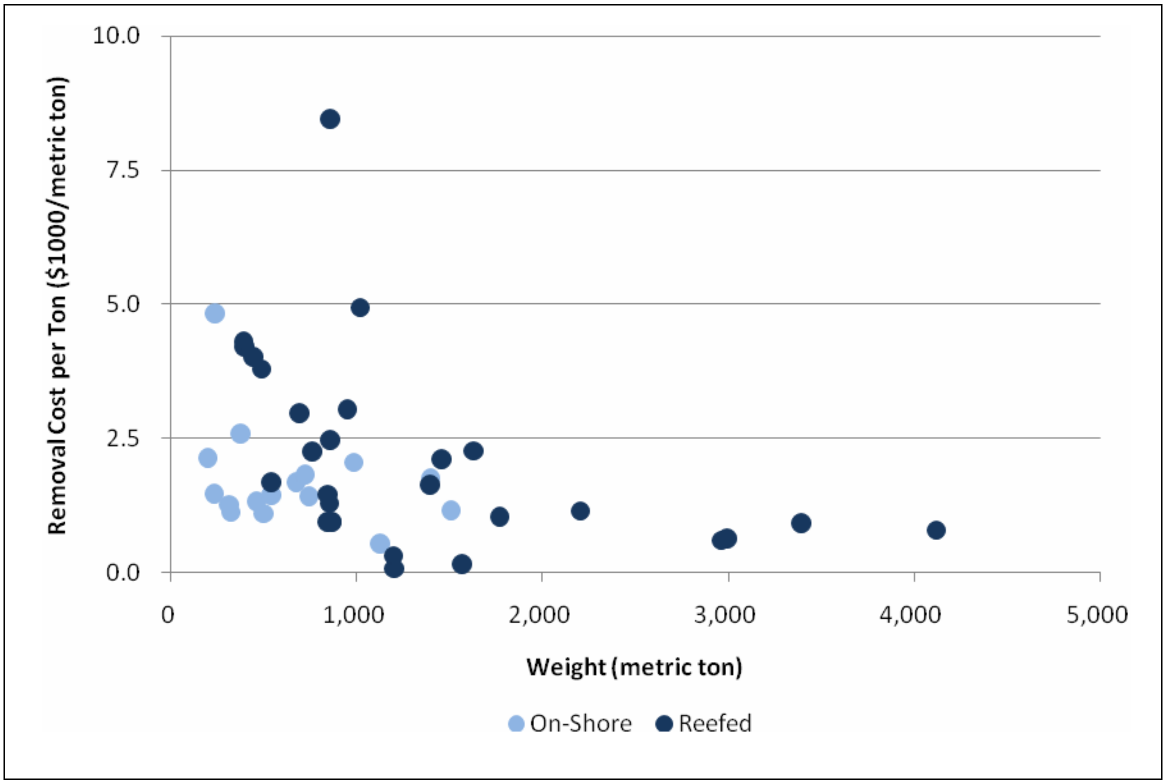


Figure E.7. Removal Cost per Ton of Fixed Platform Structures.

APPENDIX F

CHAPTER 6 TABLES AND FIGURES

Table F.1.

Net Trawling Site Clearance and Verification Contract Parameters for B&J Martin, Inc. (2007)

Contract Parameter (unit)	Parameter Value ($1000)
K_1 ($/day)	4.5
K_{21} ($/event)	2.4
K_{22} ($/event)	4.8
K_{23} ($/event)	1.2
K_{24} ($/event)	2.2
K_3 ($/incident)	At cost
K_4 ($/site)	0.8

Table F.2.

Summary Statistics of Net Trawling Site Clearance and Verification Operations in the Gulf of Mexico (2001-2005)

Parameter (unit)	Caisson – Regular Net	Caisson – Gorilla Net	Platform – Regular Net	Platform – Gorilla Net
TD (day)	3.4	5.4	6.8	8.8
LD (day)	2.2	3.2	4.4	5.8
SR (number)	1.1		2.0	
SU (number)	0.8		1.7	
GR (number)		2.5		3.5
GU (number)		2.5		4.7
N (item)	4.7	10.8	16.3	30.2
WD (feet)	69	72	124	93
AGE (year)	18.7	24	13.4	27
TC ($/job)	14,302	26,369	32,030	63,119
Number Jobs	139	20	92	49

Footnote: TD = Total number of days from dock, LD = Total number of trawl days; SR = Repairable shrimper nets; SU = Unrepairable shrimper nets; GR = Repairable Gorilla-nets; GU = Unrepairable Gorilla nets; N = Number of items collected; WD = Water depth, AGE = Age of structure upon removal; TC = Total cost of job.

Table F.3.

Site Clearance and Verification Statistics for Caisson Structures, 2001-2005

Caisson - All	2001	2002	2003	2004	2005	2001-2005
Total Cost ($)	17,516	15,677	16,271	13,938	18,061	15,964
TC Deviation	14,096	6,930	10,250	9,552	9,764	10,036
Percentage (%)	79.2	80.6	71.7	82.1	79.0	79.7
Percent Deviation	17.4	13.7	20.0	14.3	14.9	16.3
Number Jobs	21	27	22	57	40	167
Caisson - Regular						
Total Cost ($)	13,682	15,210	12,250	13,006	16,659	14,302
TC Deviation	4,952	6,716	5,923	7,540	8,084	7,205
Percentage (%)	83.8	82.7	81.4	83.7	80.5	81.3
Percent Deviation	10.4	11.7	11.0	12.0	13.3	11.6
Number Jobs	19	23	16	49	37	144
Caisson - Gorilla						
Total Cost ($)	53,934	18,358	26,995	19,646	35,357	26,369
TC Deviation	24,511	8,615	12,092	17,228	14,054	17,069
Percentage (%)	36.2	68.8	45.6	72.1	60.9	56.7
Percent Deviation	2.7	21.1	13.9	22.8	25.3	18.3
Number Jobs	2	4	6	8	3	23

Footnote: The Percentage variable represents the portion of the total cost due to the time variation of the project, and excludes the operational cost due to loss and damage of nets. TC Deviation and Percentage Deviation represent the standard deviation of the Total Cost and Percentage variables.

Table F.4.

Site Clearance and Verification Statistics for Platform Structures, 2001-2005

Platform - All	2001	2002	2003	2004	2005	2001-2005
Total Cost ($)	45,966	44,502	32,694	48,872	42,480	42,834
TC Deviation	25,994	34,111	13,686	23,776	20,892	24,390
Percentage (%)	71.1	75.0	75.7	72.7	75.5	72.3
Percent Deviation	19.8	20.2	17.1	16.2	16.1	17.4
Number Jobs	25	25	24	23	44	141
Platform - Regular						
Total Cost ($)	33,325	27,568	29,536	40,703	32,277	32,030
TC Deviation	18,549	9,450	10,826	23,853	11,437	14,689
Percentage (%)	80.0	85.0	81.7	82.1	85.5	82.1
Percent Deviation	14.5	8.2	11.1	11.2	8.8	10.3
Number Jobs	15	18	20	12	27	92
Platform - Gorilla						
Total Cost ($)	64,927	88,047	48,488	57,783	58,685	63,119
TC Deviation	24,511	36,450	17,165	21,222	22,490	26,119
Percentage (%)	57.6	49.5	45.8	62.5	59.4	55.7
Percent Deviation	19.7	19.7	5.3	15.0	11.5	13.2
Number Jobs	10	7	4	11	17	49

Footnote: The Percentage variable represents the portion of the total cost due to the time variation of the project, and excludes the operational cost due to loss and damage of nets. TC Deviation and Percentage Deviation represent the standard deviation of the Total Cost and Percentage variables.

Table F.5.

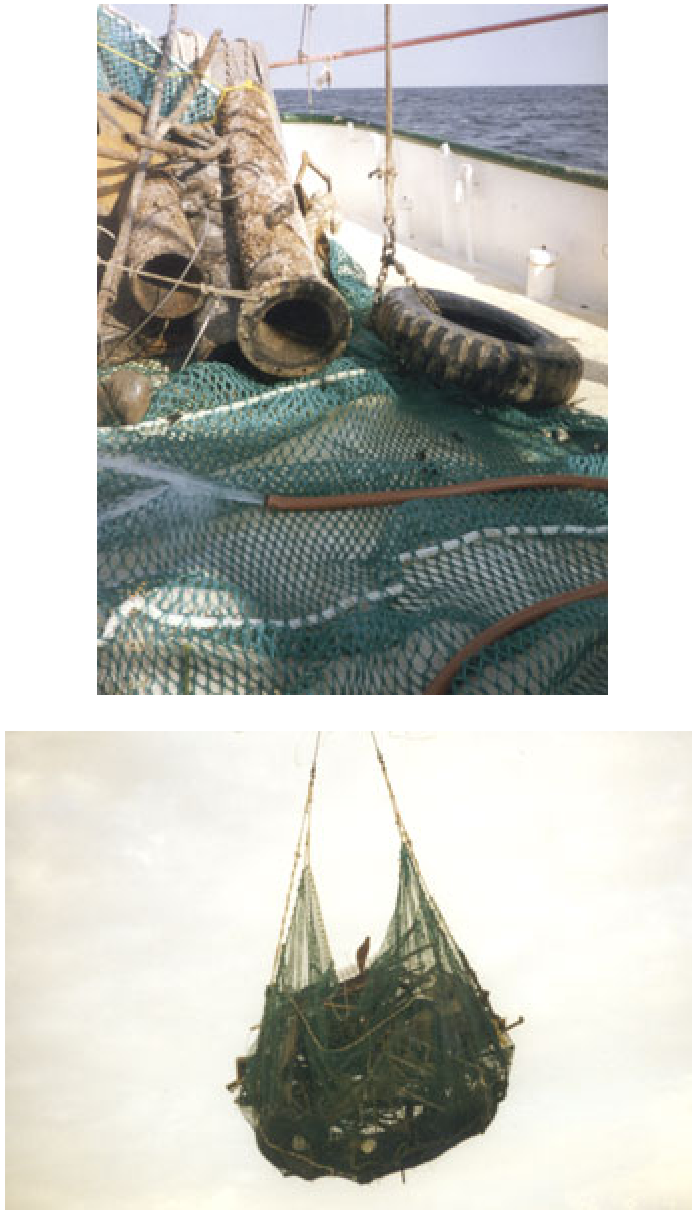
Average Total Cost and Standard Deviation for Site Clearance and Verification Operations per Water Depth and Job Type (2001-2005)

Water Depth (ft)	Caissons		Platforms	
	Average	Std. Deviation	Average	Std. Deviation
<150	15,989	10,061(166)	42,537	24,675 (100)
151-249	-	-	41,857	23,508 (33)
>250	11,728	- (1)	50,573	26,182 (8)
ALL	15,964	10,036 (167)	42,834	24,390 (141)

Footnote: The number in parenthesis represent the number of jobs in the water depth category.

Source: Kaiser and Martin, In press.

Figure F.1. Typical Debris from Site Clearance Verification.



Source: Kaiser and Martin, In press.

Figure F.2. Gorilla Net Application.

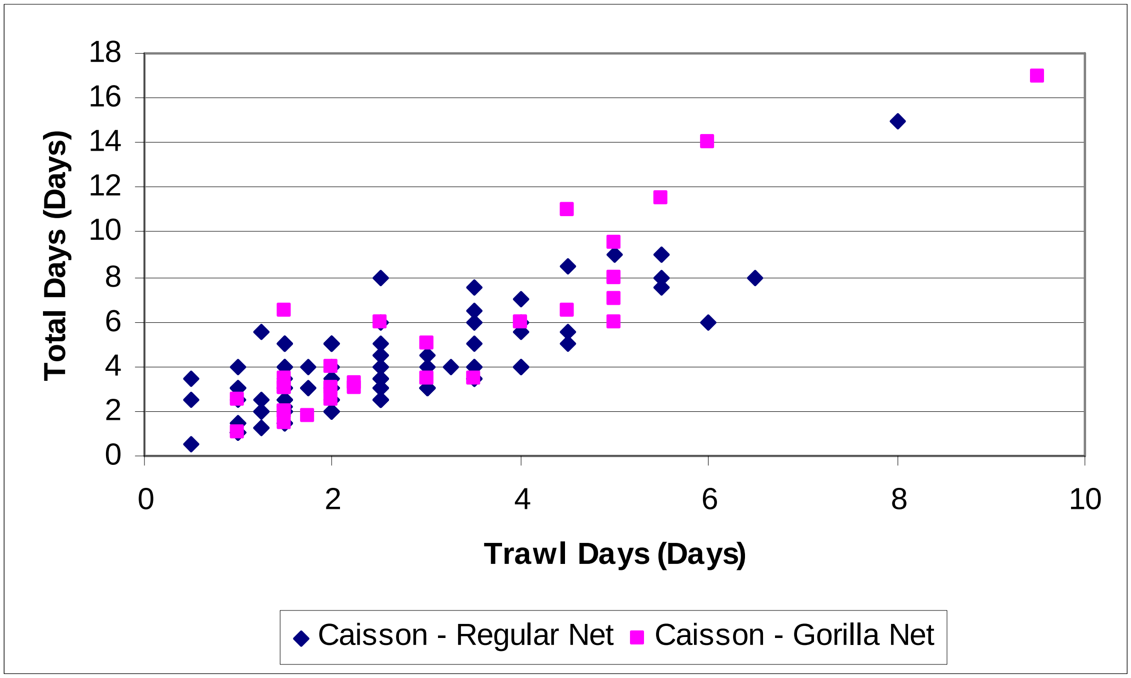


Figure F.3. Total Days and Trawl Days Correlation for Caisson Sites - Regular and Gorilla Net Applications.

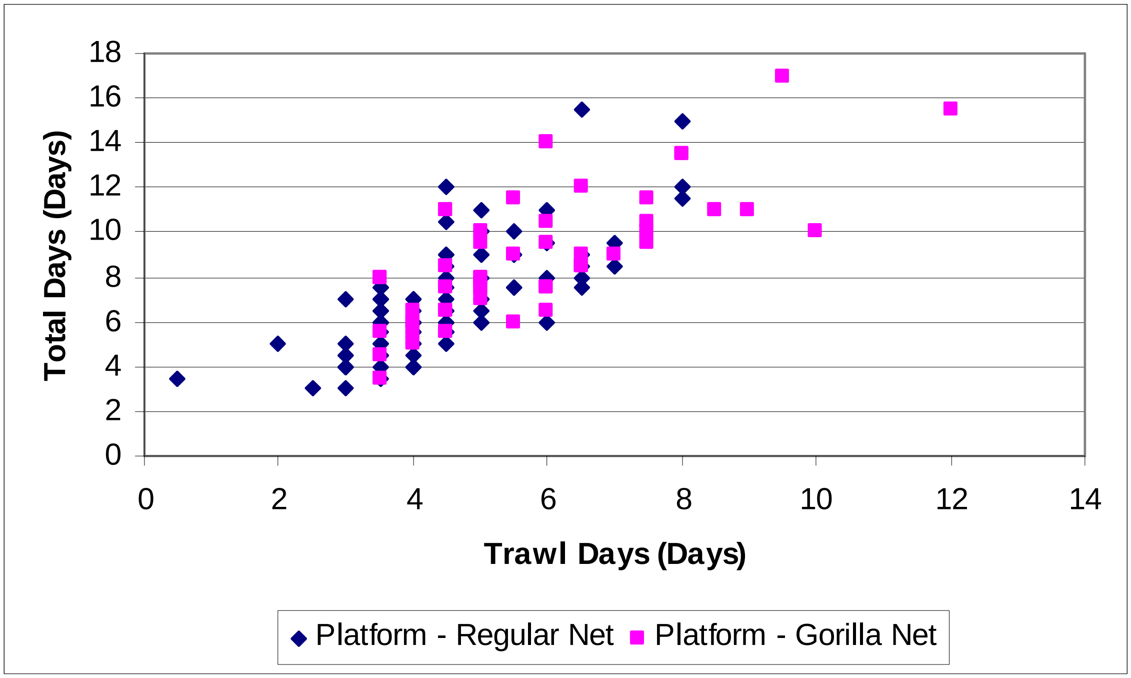


Figure F.4. Total Days and Trawl Days Correlation for Platform Sites - Regular and Gorilla Net Applications.

APPENDIX G

SAMPLE OCS DECOMMISSIONING COST REPORTING FORM

For all decommissioning activities performed during the calendar year, operators are requested to provide summary statistics in the following categories for each job performed.

Plugging and Abandonment

1. Number of wells plugged and abandoned and type (dry tree, wet tree; single completion, multiple completion)
2. Contract type
3. Water depth of each well
4. Method of operation (rig, rigless, liftboat)
5. Total cost

Structure Removal

1. Number of structures removed
2. Structure types (caisson, well protector, fixed platform)
3. Number piles per structure
4. Water depth of each structure
5. Jacket and deck weight of each structure
6. Disposition of each structure (onshore, reef)
7. Contract type (dayrate, turnkey)
8. Total cost (identify preparation, pipeline abandonment, diver survey, and related categories separately)

Site Clearance and Verification

1. Structure type (caisson, well protector, fixed platform)
2. Water depth of each structure
3. Method of site clearance (trawling, diver, combination)
4. Method of verification (trawling, diver, combination)
5. Total cost

APPENDIX H

LEGISLATIVE HIGHLIGHTS

Prior to the mid-1980s, most OCS leases were held by large oil and gas companies, and the MMS considered the financial resources of these companies sufficient to ensure performance of lease obligations and only required general bonds to be posted. Since the mid-1980's, however, a number of smaller companies have taken over much of the production on the shelf and slope, and because smaller companies generally have less financial resources, concern was raised that the government was exposed to financial risk if abandonment responsibilities were not met (Fulton, 2002).

In 1991, MMS promulgated rules that required a supplemental bond for the full amount of the estimated lease abandonment costs, less the amount of general bond coverage, for any lease that did not have at least one party deemed financially capable of fulfilling lease abandonment obligations.

In 1993, MMS increased general bond amounts and revised its regulations for supplemental bonds, such that a waiver of the supplemental bond on the lease would be granted if two conditions hold: (1) at least one lessee has lease liability less than or equal to 25% of the lessee's net worth[37], and (2) the lessee must have: a) 500 or more employees, b) $35 million in net worth, or c) $45 million in gross annual sales (MMS, 2000). If the MMS determines that estimated lease revenues and oil and gas reserves are sufficient to enable the responsible parties to pay for lease abandonment cost, the amount of the supplemental bond may be phased in over time.

To provide evidence of financial responsibility the MMS requires operators to provide insurance, a bond, a lease specific abandonment account, U.S. Treasury notes, obtain a qualified guarantor, or have sufficient net worth. Surety bonds have been the preferred method to satisfy an operator's obligations. Insurance is a viable solution for the uncertainty of an oil spill, but it is generally not a good vehicle for the certainty of decommissioning.

The fundamental concept behind a surety bond is to guarantee that someone will perform a duty[38]. In the case of offshore leases, the duty is imposed by law to plug and abandon all wellbores and clear the site of all production infrastructure to ensure performance of regulatory requirements. The bond provides an independent third party to ensure that the principal, the person who agrees to the duty, performs, or that there is money available to complete the obligation. The underwriting process of surety bonding is considered a line of insurance, but it has many similar characteristics to a bank lending process because the applicant in either case is being judged as a credit risk. The surety does not lend money to the contractor, but is committing

[37] The net worth of a company represents the total equity interest that all the shareholders own in the operation, and is calculated as the difference between the total assets and liabilities of the company.
[38] Webster's Dictionary defines surety as, "The state of being sure: A pledge or other formal engagement given for the fulfillment of an undertaking; the one who has become legally liable for the debt, default, or failure in duty of another."

its financial resources to guarantee an operator's performance. On a case-by-case basis, the MMS has allowed a lessee to furnish a third-party guarantee or a lease-specific abandonment account as alternatives.

In 1998, MMS updated and revised the procedures used in assessing the financial strength of OCS leases in the requirements to submit a supplemental bond. As specified in the NTL 98-18N, Supplemental Bonding Procedures, a waiver of the supplemental bond requirement on a specific lease or ROW may be granted by the MMS if at least one record title lessee meets the criteria established. Production and financial ratios[39] are currently employed to assess lessee's financial strength and reliability (MMS, 2001).

In 2001, Secretary Norton formed a Bonding Task Force comprised of the Bureau for Land and Minerals Management, Office of Surface Mining and MMS, to examine the scope and severity of the changes in the bonding market and to develop recommendations to address identified problems (Schlief, 2002; Fulton, 2002). No significant changes were made to the bonding levels or mechanism as a result of the review.

In 2005, Hurricanes Katrina and Rita caused widespread destruction in the GOM, and unprecedented losses to the offshore industry in terms of physical damage and business interruption, estimated at $15 billion. The disruption to coastal communities and facilities, combined with an increase in demand for labor and offshore support vessels in the aftermath of the storms, led to a significant increase in dayrates across the service sector, which impacted the cost of decommissioning services for a sustained period of time.

[39] The MMS use two financial ratios to assess strength and reliability: the current ratio and the debt-to-equity ratio. The current ratio is the ratio of the current assets (CA) to current liability (CL), where CL comprise debts that come due within one year and CA represent the ability to satisfy those obligations. A measure of the amount of leverage in a company's capital structure is its debt-to-equity ratio. The higher the proportion of loans the higher the firm is leveraged.

APPENDIX I

RELATED DEPARTMENT OF THE INTERIOR BONDING REQUIREMENTS

Congress has enacted several laws and Federal agencies have developed regulations requiring companies to demonstrate that they have sufficient financial resources to perform the reclamation and clean up of sites after the completion of exploration, mining, and production activities. The Department of Interior's (DOI) bureaus may require a surety bond or proof of other financial security prior to approving a plan of operation or issuing a lease or permit. A summary of some of the bonding requirements in laws administered by the DOI include:

- The General Mining Law of 1872, 30 U.S.C.A. sec. 22-45 applies to "locatable minerals" such as precious metals and gemstones. The DOI requires 100 percent of the estimated reclamation cost to be secured by a bond.

- The Mineral Leasing Act of 1920 (30 U.S.C.A. sec. 181-287) applies to coal, oil, gas, phosphate, sodium, potassium, and other minerals and requires adequate bonds for bonus bids, onshore surface and downhole operations, and pipeline rights-of-way. By regulation, fixed bond amounts per lease for onshore oil and gas exploration are required.

- The Outer Continental Shelf Lands Act of 1953 (67 Stat. 462), as amended (43 U.S.C. 1331, et seq.) applies to offshore oil and gas and allows for bonds. Bonds are required to guarantee offshore end-of-line activities such as plugging wells and platform removal.

- The Surface Mining Control and Reclamation Act of 1977 (30 U.S.C.A. sec. 1201-1328) applies to surface coal mining on public and private lands and requires performance bonds sufficient to cover 100 percent of the estimated reclamation cost.

- The Oil Pollution Act of 1920 (33 U.S.C.A. sec. 2701-2761) requires a demonstration of financial capability, which is frequently met with an insurance policy.