Offshore Decommissioning Cost Estimation in the Gulf of Mexico

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Abstract: Decommissioning offshore structures represents the end of the production life cycle, when wells are plugged and abandoned, infrastructure is removed, and the site is remediated and cleared of debris. Decommissioning operations are generally routine, involving standard, low-technology methods, over distinct stages and relatively short time horizons. Offshore operations are more uncertain and costly than onshore, however, due to the hostile ocean environment. Cost estimation is an important aspect of the business since engineers, project managers, and financial accountants frequently perform cost estimates in support of evaluating decommissioning alternatives, divestiture opportunities, and liability assessment. The purpose of this paper is to provide an overview of the factors that impact the primary stages of decommissioning and to describe a general methodology to estimate cost functions. A description of the regulatory requirements is presented along with the empirical construction of cost functionals for shallow-water developments in the Gulf of Mexico.

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Introduction

There are approximately 4,000 structures in the federally regulated Outer Continental Shelf (OCS) of the Gulf of Mexico (GOM) used to produce oil and natural gas. The OCS of the GOM begins seaward three nautical miles from the Louisiana, Alabama, and Mississippi shorelines, and three marine miles (nine nautical miles) from the Texas and west Florida shorelines, and extends 200 miles through the Exclusive Economic Zone. The GOM is the most extensively developed and mature offshore petroleum province in the world. More than 40,000 wells have been drilled in the OCS since offshore production began in 1947, and nearly 33,000 miles of pipeline are currently in use.

The basic size and function of an offshore structure result from the requirements of the development plan (McClelland and Reifel 1986), which vary depending upon the time of development; reserve size; proximity to infrastructure; and operating, economic, environmental, and strategic considerations. Shallow water developments in the GOM, defined as water depths less than 1,000 ft, employ caissons (Fig. 1), well protectors (Fig. 2), fixed platforms (Fig. 3), and subsea completions.

Topside facilities define the function of the structure; the supporting substructure and foundation defines the platform type. A caisson is a cylindrical or tapered tube enclosing a well conductor and is the minimum structure for offshore development of a well. Structures that provide support through a jacket to one or more wells with minimal production equipment and facilities is referred to as a well protector. Subsea systems include seafloor and surface equipment: seafloor equipment includes subsea wells, manifolds, control umbilicals, and flowlines; surface equipment includes the control system and other production equipment located on a host platform. Fixed platforms resemble the jacket structure of well protectors, but are larger and more robust, self-contained structures, that include facilities for drilling, production, and combined operations. The distribution of GOM structures according to type, water depth, and planning area is shown in Table 1.

In the deepwater GOM, compliant towers, spars, subsea systems, tension leg platforms, and floating production units are also employed, but in significantly smaller numbers (Table 2, Fig. 4). Fixed platforms have an economic water depth limit of about 1,500 ft (457 m), whereas compliant towers are viable for water depths ranging between 1,000 and 3,000 ft (304 and 914 m). Tension leg platforms (TLPs) are frequently used in 1,000–5,000 ft (304–1,524 m), and spars, semisubmersible production units, subsea systems, and floating production, storage and offloading systems (FPSO) may be used in water depths ranging up to and beyond 10,000 ft (3,048 m) (Baud et al. 2002).

Structures are installed to produce and process hydrocarbons, and when the time arrives that the cost to operate a structure (maintenance, operating personnel, transportation, fuel, etc.) exceeds the income from the hydrocarbons under production, the structure exists as a liability instead of an asset and becomes a candidate for divestiture or decommissioning. Federal regulations require that all structures on a lease be completely removed and all wells permanently plugged and abandoned within one year after the lease is terminated, which typically occurs when production on the lease ceases. Since 1947, over 2,200 structures have been removed from the GOM, and over the past decade, 125 structures per year have been removed on average.

The purpose of this paper is to construct cost functions that characterize shallow-water decommissioning activity across the three main stages of the operation: well plugging and abandonment, structure removal, and site clearance and verification. The outline of the paper is as follows. The general regulatory require-

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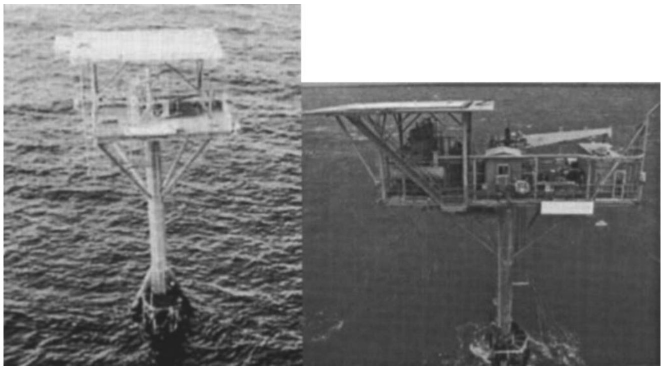

Fig. 1. Caisson structures (source: Twachtman Snyder & Byrd, Inc., with permission)

ments of decommissioning are first reviewed, and factors that impact the cost of decommissioning are enumerated. Empirical cost functions are estimated based on survey data, and examples are used to illustrate their application. Conclusions complete the paper.

Regulatory Requirements

Different government bodies regulate the decommissioning and abandonment of offshore structures, and the regulatory body with primary responsibility is dependent on the physical location of the structure. State agencies are responsible for structures located in state waters, whereas the Minerals Management Service (MMS) is the federal agency responsible for decommissioning activities in the OCS of the United States (Pulsipher 1996).

The basic aim of a decommissioning project is to render all wells permanently safe and remove most surface/seabed signs of production activity. The general requirements for decommissioning are specified in Federal Registry *30 CFR*, Sec. 250.1703 and require that all wells be permanently plugged and abandoned, all platforms and other facilities be removed, and the seafloor cleared of all obstructions created by the operations within one year after the lease or pipelines right-of-way terminates (Federal Register 2002).

The operator is required to submit form MMS-124, "Sundry Notices and Reports on Wells," and receive approval for plug and abandonment (P&A) operations. Federal regulations are written

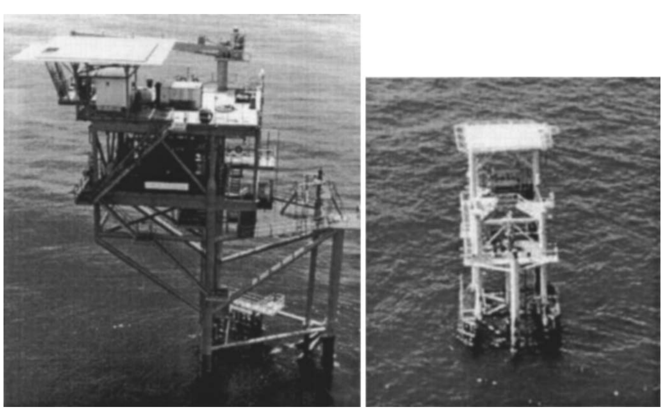

Fig. 2. Well protector structures (source: Twachtman Snyder & Byrd, Inc., with permission)

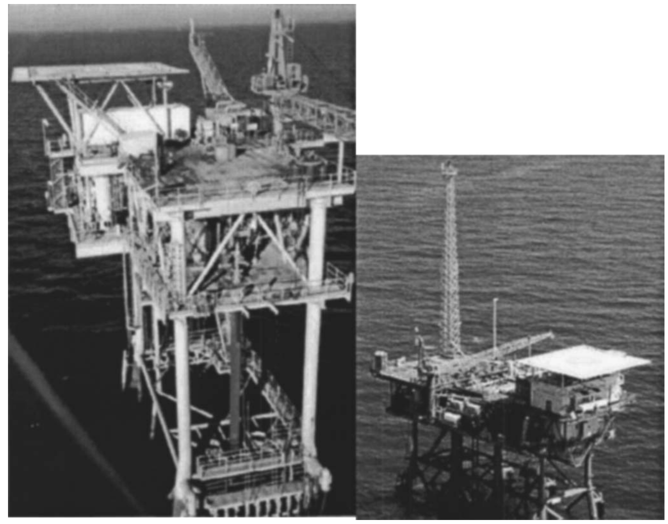

Fig. 3. Fixed platform structures (source: Twachtman Snyder & Byrd, Inc., with permission)

to have general application to all wells and specify the minimum requirements necessary. 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. Before beginning operations, the District Supervisor, a federal official, is required to be notified at least 48 h prior to the operation.

All wellheads and casings are required to be removed to a depth at least 15 ft (5 m) 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 2,640 ft (805 m). 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 3 ft (1 m) 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. Strict regulations govern the manner in which explosives are employed in severance operations (Kaiser and Pulsipher 2003). 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 15 ft (5 m) below the mudline.

All abandoned well and platform locations in water depths less than 300 ft (91 m) 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;

J. Constr. Eng. Manage., 2006, 132(3): 249-258

Table 1. Gulf of Mexico Infrastructure (2003)

Water depth (ft)	WGOM			CGOM			GOM
	CAIS	WP	FP	CAIS	WP	FP	Auxiliary[a]
0–20	1	0	0	200	10	35	79
21–100	79	25	119	767	268	710	318
101–200	3	17	82	48	63	490	73
201–400	1	4	85	1	12	320	31
400+	0	0	13	0	3	43	4
Total	84	46	299	1,016	356	1,598	505

Note: WGOM and CGOM refer to the Western and Central Gulf of Mexico planning area; CAIS=caissons; WP=well protectors; and FP=fixed platforms, respectively.

[a]An auxiliary structure has never produced hydrocarbons, but serves in a support role, as a quarter facility, flare tower, storage platform, etc.

- Single-well caissons—600 ft (183 m) radius circle centered on the well; and
- Platforms—1,320 ft (402 m) radius circle centered on the platforms geometric center.

Platforms and single-well caissons in water depths less than 300 ft (91 m) 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.

Factor Description

The time and cost to perform decommissioning activities depends on a number of factors. Many characteristics of the operation are observable, but many others are not, and there is no way to identify and measure all of the factors that impact each stage of decommissioning. In practice, however, it is only necessary to identify factors that describe the essential elements of the process. The factors that we will consider include the physical characteristics of the well and structure, location, contract type, disposition options, operator preferences, market conditions, construction practices, the occurrence and duration of exogenous events, and contract specifications.

Table 2. Deepwater Production Facilities in the Gulf of Mexico, Including Plans through 2006

Development strategy	Number
Fixed platform	5
Compliant tower	3
Tension leg platform	8
Small TLP	6
Spar	4
Truss spar	8
Semi-FPS	5
Subsea	164

Note: Data adapted from MMS.

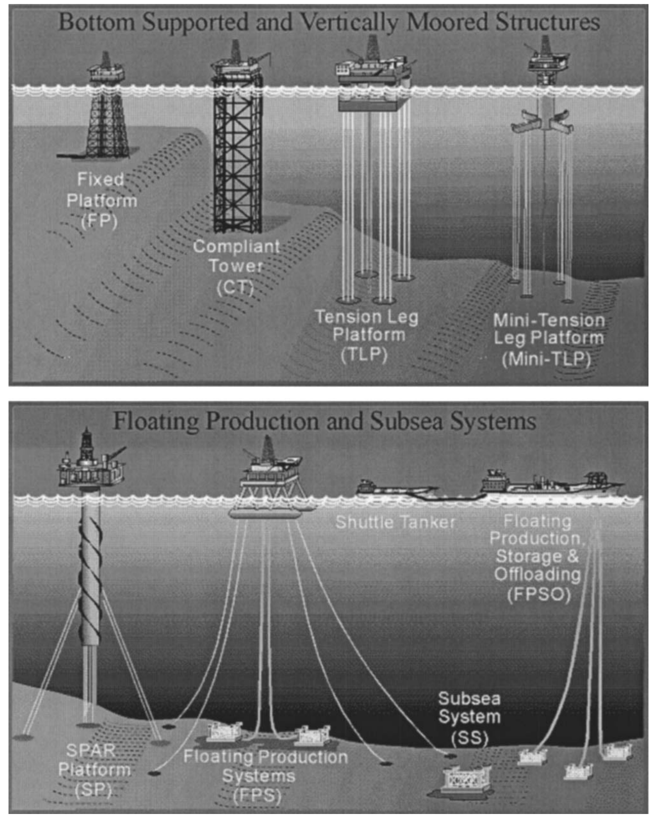

Fig. 4. Deepwater development strategies (source: MMS)

Well Complexity

Well complexity is a key factor in determining the number of bridge/cement plugs that have to be set and the number of casing strings to recover and remove. Bridge/cement plugs are placed at various locations within the well bore to destroy the permeability within the formation and stabilize the well until geologic forces can reestablish the natural barriers that existed before the well was drilled. Well complexity is not a uniquely defined measure, however, and depends as much on the experience and contingency planning of the service company as on the downhole conditions encountered. A complete well bore history is essential to planning and executing a P&A job, but if good records are not available or do not match the well configuration, planning success may be impacted. Ideally, operators should develop an abandonment plan before the well is drilled, which should be updated whenever the well's mechanical configuration is changed.

Structure Characteristics

Deck size and weight; jacket size and weight; the number of piles, skirt piles, conductors, wells, and pipeline attachments; and the diameter and weight of piles and conductor strings are the primary physical characteristics of offshore structures which impact the cost and time of removal. 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 expected during the operation. In shallow water, the deck is normally the heaviest lift, while as the water depth increases, the jacket weight normally exceeds the 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.

Location

Location is an important factor since location determines the distance to shore, water depth, and proximity to the nearest reef site. Distance to shore is an important characteristic since it determines the time and cost for mobilization/demobilization, offloading and transport, and service cost. For most structures in the GOM, it usually takes about a day to arrive at site and to prepare for the operation. Structures that are greater than fifteen miles from shore are typically out of range for daily shift changes by crewboat and will require accommodations during decommissioning. 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.

Water Depth

Water depth is a primary variable in offshore construction and P&A activities since increasing water depth generally requires the size of the rig to increase, reducing operational flexibility, and increasing the time and cost of the operation. In P&A operations, water depth is not expected to be a significant factor in water depth less than 600 ft (180 m), since within this depth category the type of rig required is relatively homogeneous. 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 diving cost and generate constraints on diving time and operating procedures, and in general, will increase the sensitivity of the operation to environmental factors.

Removal Method

Decommissioning alternatives are generally classified as total removal, partial removal, and toppling-in-place. In a total removal, after the conductors and piles have been cut and removed, the jacket structure is lifted out of the water and welded to a materials barge for transport. The deck and jacket structure may be scrapped or stored onshore, moved to a new location and reinstalled, sold to another operator, or converted to an artificial reef site. In a partial removal, the bottom-half of the structure is left standing vertically in the water column, while the top-half section of the jacket is severed and placed next to the base or removed to shore. 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.

Rigs to Reef

The suite of alternatives that leave part or all of the abandoned structure in the marine environment is often referred to as "rigs-to-reef." 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 Van Sickle 1987), whereas 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 (Table 3).

Table 3. Reef Capture Statistics[a] in the Gulf of Mexico

Water depth (ft)	WGOM (%)	CGOM (%)	GOM (%)
0–20	0	0	0
21–100	11	1	2
101–200	65	31	40
201+	82	58	65
Total	42	13	19

[a]Reef capture statistics are calculated from the inception of the Texas and Louisiana Artificial Reef Program: 1991–2002 (WGOM) and 1987–2002 (CGOM).

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 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. Subsea wellheads, production manifolds, and equipment designed to high specification and deployed for a short production life (e.g., ten years or less) are usually the best candidates for reuse. Timing and scheduling present additional complicating factors for reuse opportunities.

Environmental Conditions

Wind, waves, current, and weather impact offshore operations in the GOM throughout the year, especially during the peak hurricane season, from August 15 to October 15, and the winter season, from November 30 to March 31. Although the offshore industry is known for its ingenuity, technological advancements, and the ability to withstand harsh environments, extreme weather is one of the few factors that cannot be overcome. Weather may delay an operation or require the crew to demobilize to shore, and during this time drilling and 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. The party exposed to weather risk will usually require a higher risk premium to manage the potential cost overruns.

J. Constr. Eng. Manage., 2006, 132(3): 249-258

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. In P&A operations, for instance, a rig is normally used with the derrick, draw works and surface equipment brought to site. In a rigless approach, a crane is used to pull pipe, and coil tubing and wireline and electric line units are used to assist with the placement of cement plugs. The rigless approach is used primarily offshore and is normally less expensive than the rig method, although the method chosen is dictated by engineering requirements, contractor preference, and/or equipment availability.

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. In P&A operations, it is not uncommon to find downhole obstructions in the production tubing, leaks, and corrosion. 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.

Management Decisions

Management decisions regarding how a field is abandoned are reflected in the manner structures are grouped for abandonment, the value of delaying removal, and ultimately, the terms of the contract. The salvage value associated with the equipment, deck, and jacket will impact the net decommissioning cost, and sometimes depends as much on luck and the timing of removal, as on the strategic decisions of operators.

Operator Preference

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. For example, between November 15, 2000 and 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.

Project Management Experience

The experience and expertise of the project management team overseeing the operation is an important factor in managing the cost of the operation and ensuring the removal plan satisfies the company objectives. The project management team acts as the agent of the operator and 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.

Market Conditions

Construction equipment used in removal operations range from liftboats to derrick barges. Derrick barges (DB) 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 range from 10 to 70 t, whereas a small DB can range from 150 to 300 t. Large hull vessels have crane lift capacities of 600–1,600 t. A few large DBs in the GOM have lifting capability greater than 2,000 t. The numbers of vessels available at a given point in time change with the local supply and demand conditions and the ease in which vessels can be transported between offshore regions. Market rates for DB spreads depend primarily upon its depth rating and crane vessel capacity.

Contract Specification

Plug and abandonment contracts are written on either a day rate or turnkey basis, and both types are popular in the GOM. In a day-rate contract, the service company performs activities under the supervision of the operator who "holds" the downtime, weather, and problem well risk. In a turnkey contract, the service company bids a "lump sum" for the completed job, and is exposed to the full risk of the operation. For two jobs identical in all respects except contract type, the cost of a turnkey contract would be expected to be more expensive than a day-rate contract since the service company is fully exposed to capital, environmental, and technical risk. The risk premium of the contract varies with the market and experience of the contractor, job specification, and other factors.

The team in charge of structure removal will let the contract on the job 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 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. Typically, a lump sum (base) bid is specified that includes weather downtime, except downtime due to named tropical storms, for work during the prime season (from May 15 to October 15). 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. A lump

J. Constr. Eng. Manage., 2006, 132(3): 249-258

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 terms of most decommissioning contracts in the GOM are turnkey with extra rates specified in the bid. 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.

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, night-time 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.

Plugging and Abandonment Cost Estimation

Operational Requirement

Wells in the OCS must be permanently P&A within one year after the lease terminates. Plug and abandonment may occur before, during, or after removal preparation activities are complete—depending on the scope of work and contractor requirements—but all wells must be P&A prior to cutting and removing the conductors. Plugging is normally done well in advance of removal operations. Techniques used to P&A wells are based on industry experience and conformance with regulatory standards and requirements.

P&A Cost Statistics

Data for P&A cost assessment was compiled from job reports in the Gulf of Mexico conducted by Tetra Applied Technologies, L.P. between 2002–2003 (Kaiser and Dodson 2003). The sample set consisted of 118 jobs and 390 wells.

The primary factor determining P&A cost is the degree of difficulty encountered with the well. Table 4 depicts the average total cost, C_1, and number of days, ND, required to perform P&A operations according to contract type and job specification. NJ and NW denote the number of jobs and number of wells in each category. Jobs are specified as P&A or temporary plug and abandon (T&A) operations. In T&A operations, an operator expects to reenter the well at a later date, and so plug requirements are not as rigorous, casing string is neither cut nor pulled, etc. For all things equal, the average cost of a T&A job is expected to be less than P&A work. Most day-rate contracts in the sample set are written for T&A jobs, whereas most turnkey contracts are written for P&A operations.

Table 4. Plug and Abandonment Cost and Operational Statistics (2002–2003)

Parameter (unit)	Dayrate		Turnkey	
	P&A	T&A	P&A	T&A
C_1 ($/job)	412,923	96,038	384,586	312,273
C_1/NW ($/well)	276,162	56,562	141,379	156,381
ND (day/job)	32.7	15.4	25.4	18.6
ND/NW (day/well)	18.4	9.7	9.2	9.2
C_1/ND ($ job/day)	12,628	6,236	15,141	16,789
C_1/ND ($ well/day)	15,009	5,831	15,367	17,324
NJ (job)	7	44	54	13
NW (well)	13	84	259	34

Note: Data adapted from Kaiser and Dodson (2003).

The normalized cost for P&A operations should exceed the cost to T&A a wellbore, and this is supported by the empirical data for dayrate contracts. Similarly, for a given job specification, a turnkey contract should be priced at a premium relative to a day-rate contract, but here the empirical results are contrary to expectation. For T&A operations, the normalized total cost for a turnkey operation exceeds the dayrate by about $100,000/well, whereas for P&A operations, the total cost for a day-rate contract exceed the turnkey contract by approximately $140,000/well. The small sample size of P&A dayrate contracts and self-selection on the part of the contractor may partially explain the mixed outcome.

P&A Model Results

The cost to P&A structure s, $C_1(s)$, is modeled through a linear functional

$$C_1(s) = \alpha_0 + \sum_{i=1}^{7} \alpha_i X_i \tag{1}$$

where X_1=JOB=job specification; X_2=NW=number of wells; X_3=RIG=rig deployment; X_4=WB workboat deployment; X_5=SEASON=season when the work began; X_6=WOW=waiting on weather; and X_7=ND=number of days. The number of days to complete the job and the number of wells are numerical variables, whereas the job specification, rig and workboat deployment, season, and waiting on weather are categorical variables, defined in terms of binary indicators: JOB=0, T&A operation; JOB=1, P&A operation; RIG=0, rigless operation; RIG=1, rig operation; WB=0, workboat not employed; WB=1, workboat employed; SEASON=0, April 1–October 31; SEASON=1, November 1–March 31; WOW=0, no weather interruption; WOW=1, weather interruption. The coefficients of the functional, α_i, $i=0,\ldots,7$, are estimated through least-squares regression modeling based on the survey data collected. The coefficient α_0 represents a fixed-term component, whereas α_i, $i=1,\ldots,7$, are associated with the corresponding model variables.

J. Constr. Eng. Manage., 2006, 132(3): 249-258

Table 5. Plug and Abandonment Cost Models—1

	$C_1(s)=\alpha_0+\alpha_1\text{JOB}+\alpha_2\text{NW}+\alpha_3\text{RIG}+\alpha_4\text{WB}+\alpha_5\text{SEASON}+\alpha_6\text{WOW}+\alpha_7\text{ND}$		
Coefficient	Model I	Model II	Model III
α_0	−47,628 (−1.3)	50,704 (1.4)	11,673 (*)
α_1	100,082 (1.9)	79,190 (1.3)	55,711 (1.1)
α_2	8,704 (1.4)	21,187 (3.1)	12,536 (1.8)
α_3	16,021 (*)	22,745 (*)	25,749 (*)
α_4	153,216 (2.3)	208,784 (2.7)	143,590 (1.5)
α_5			251,150 (4.2)
α_6			19,173 (3.2)
α_7	6,498 (6.1)		
n	113	113	68
R^2	0.74	0.62	0.75

Note: An asterisk indicates t statistic <1. Data adapted from Kaiser and Dodson (2003).

T&A jobs are generally simpler to perform than P&A jobs, so if all other factors are held fixed, the JOB coefficient should be positive. As the number of wells increase, the total cost and time to perform the operation is expected to increase, and if a rig or workboat is employed or weather days are encountered, costs are likely to be greater. The model coefficients of RIG, WB, and WOW are thus expected to be positive. The season in which the job is performed may impact the time and cost to perform the service, since ocean and weather conditions during the summer season are less likely to cause operational delay. The model coefficient for SEASON is expected to be positive. Some factors of the data set may not be available for analysis because they were not reported or recorded, or because the entries are missing. The number of model variables will decrease in such cases and the model specification will need to be adjusted accordingly.

The model results for P&A costs under three model specifications are shown in Table 5. Seasonal and waiting on weather data were not available for all the jobs in the data set, and Model (I) differs from Model (II) due to the inclusion of the ND variable in the specification. In Model (III), a subset of the data that included waiting on weather data was examined separately. P&A cost functionals are reported in Table 6 for job data decomposed according to contract type and job specification.

Example: The cost of a four-well turnkey P&A contract performed in July with a rig and a workboat and expected to take 15 days to complete is estimated from Table 6 as follows:

$$C_1(s) = 30{,}051 + 6{,}510(4) + 36{,}241(1) + 112{,}715(1) - 9{,}284(0) + 8{,}562(15) = \$\,333{,}500.$$

For a turnkey T&A contract, the cost is estimated from Table 6 as follows:

$$C_1(s) = -\,115{,}188 + 36{,}543(4) + 150{,}580(1) + 70{,}896(1) + 59{,}524(0) + 9{,}346(15) = \$\,392{,}650.$$

Table 6. Plug and Abandonment Cost Models—2

	$C_1(s)=\alpha_0+\alpha_1\text{NW}+\alpha_2\text{RIG}+\alpha_3\text{WB}+\alpha_4\text{SEASON}+\alpha_5\text{ND}$		
	Dayrate	Turnkey	
Coefficient	T&A	P&A	T&A
α_0	−21,588 (−1.5)	30,051 (*)	−115,188 (−1.2)
α_1	16,267 (2.9)	6,510 (1.0)	36,543 (2.5)
α_2	122,231 (3.3)	36,264 (*)	150,580 (1.1)
α_3	108,870 (2.9)	112,715 (1.8)	70,896 (*)
α_4	−6,356 (*)	−9,284 (*)	59,524 (*)
α_5	4,790 (8.0)	8,562 (3.6)	9,346 (3.9)
n	44	54	13
R^2	0.89	0.61	0.95

Note: An asterisk indicates t statistic <1. Data adapted from Kaiser and Dodson (2003).

Structure Removal Cost Estimation

Operational Requirement

The removal of the topside facilities, deck, conductors, piles, and jacket is the core of the decommissioning project and typically the most expensive stage. 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 (5 m) below the mudline; and the jacket needs to be lifted and taken onshore, to another location for reuse, or to an artificial reef site.

Removal options are made as part of the overall decommissioning assessment, and since topsides may be integrated, modular, or hybrid in nature, removal may be achieved in one piece; in groups of modules; in small pieces; or combinations thereof (Manago and Williamson 1997). Topsides removal follows the installation process in reverse sequence. Modules are removed and placed on a cargo barge and secured by welding pieces of steel pipe to the deck of the barge. The deck section or support frames are removed after cutting the welded connections between the piles and the deck legs. The deck is then seated in the load spreaders and secured for disposition. Conductor severing and removal may take place as part of P&A activity or during the structure removal operation. Conductor length determines the number of sections to be cut, stored, and offloaded, which in turn influences the type and number of cargo barges required for the operation.

Removal Cost Statistics

Data to estimate removal cost was obtained from Twachtman Synder and Byrd, Inc., for 50 decommissioning projects performed during 1998–2003. The data set described in (Kaiser et al. 2003) was updated, filtered, and reprocessed so that only the removal stage of the operation was examined. The data were not adjusted for inflation.

Forty-five of the fifty jobs involved removing a well protector or fixed platform, twelve structures participated in a reef program, and four of the reefed structures toppled-in-place or partially removed. The average cost to remove a structure were roughly \$1,000 per ton (Table 7). The cost to remove a ton of caisson is almost twice the cost to remove a ton of well protector or fixed platform (Table 8), and as the water depth increases, the cost per ton decreases, probably due to scale economies. Removal cost is a negative function of structure complexity, indicating that a large fixed cost component is present in the operation.

J. Constr. Eng. Manage., 2006, 132(3): 249-258

Table 7. Structure Removal Cost and Operational Statistics (1998–2003).

Metric (unit)	Mean	Standard deviation	Minimum	Maximum
C_2 (\$1,000)	1,442	1,641	162	10,776
WD (ft)	150	90	25	350
MW (t)	903	1,031	30	4,000
TW (t)	1,440	1,505	45	5,300
NP	4.8	2.7	1	12
NW	3.6	3.5	0	14
CF	13.1	9.4	3	41

Note: Data adapted from Kaiser et al. (2003).

Removal Model Results

The cost to remove structure s, $C_2(s)$, is described through a linear specification

$$C_2(s) = \alpha_0 + \sum_{i=1}^{7} \alpha_i X_i \tag{2}$$

where X_1=ST=structure type; X_2=WD=water depth (ft); X_3=CF=complexity factor; X_4=MW=maximum component weight (t); X_5=TW=total structure weight (t); X_6=REEF=structure disposition; and X_7=TOW=reef removal method. The water depth, complexity factor, maximum component weight, and total structure weight are numeric variables. Structure type, structure disposition, and removal method are binary indicators. Note that although the same notation is used for the $C_1(s)$ and $C_2(s)$ model functional, the coefficients α_i, $i=0,\ldots,7$, are not identical because the data set from which they are derived and the model specification are different.

Structure type distinguishes between simple and complex structures through an indicator variable: ST=0, caisson and ST=1, otherwise. The complexity factor CF is a measure that counts the number of conductors (N_c), pipeline attachments (N_{pl}), piles (N_p), and skirt piles (N_{sp}), associated with the structure:

$$CF = N_c + N_{\mathrm{pl}} + N_p + N_{\mathrm{sp}}$$

The derrick barge lift capacity required to remove the structure is estimated by the maximum component weight MW:

$$\mathrm{MW} = \max(W_d, W_j)$$

where W_d and W_j denote the deck and jacket weight of the structure. The size of the deck, equipment weight, number of modules, and number of piles/conductors, determine the weight, size constraint, and number of cargo barges required for the operation. The total weight of the structure is defined as the weight of the deck and jacket, plus the weight of equipment (W_e), piling (W_p) and conductors (W_c):

$$\mathrm{TW} = W_d + W_j + W_e + W_p + W_c$$

Table 8. Removal Cost to Total Weight Ratio (\$1,000/t)

Water depth (ft)	Caisson	Well protector	Fixed platform
0–100	5.87 (3)	3.75 (12)	2.50 (4)
101–200	6.17 (2)	1.64 (6)	1.06 (9)
201+	—	1.40 (3)	0.65 (11)

Note: The number in parentheses represent the sample size. Data adapted from Kaiser et al. (2003).

Table 9. Removal Cost Models (\$1,000)

	$C_2(s)=\alpha_0+\alpha_1\mathrm{ST}+\alpha_2\mathrm{WD}+\alpha_3\mathrm{TW}+\alpha_4\mathrm{REEF}+\alpha_5\mathrm{TOW}+\alpha_6\mathrm{CF}$			
Coefficient	Model I	Model II	Model III	Model IV
α_0	1,101 (2.1)	1,029 (1.8)	1,026 (2.1)	1,009 (1.6)
α_1	416 (1.0)	292 (1.1)	306 (1.0)	283 (1.0)
α_2	−4.84 (−1.4)	−4.8 (−1.4)	−4.45 (−1.3)	−4.61 (−1.3)
α_3	0.61 (2.7)	0.65 (2.5)	0.72 (3.3)	0.67 (2.5)
α_4	−452 (−1.8)	−275 (−1.2)	−329 (−1.1)	−301 (−1.3)
α_5		431 (1.1)	133 (1.4)	
α_6		10.9 (*)		32.6 (*)
n	50	50	50	46
R^2	0.48	0.52	0.51	0.49

Note: An asterisk indicates t statistic <1.

If a structure is donated to a reef program, the binary variable REEF is used to indicate disposition: REEF=0, on-shore removal and REEF=1, artificial reef donation. The binary variable TOW specifies the manner in which the structure is donated. If the structure is toppled-in-place or partially removed, TOW=0; if the structure is towed to site, TOW=1.

The total cost of structure removal is expected to increase with structure complexity, and so the coefficients of the variables ST and CF are expected to be positive. As the maximum component weight and total structure weight increase, the cost of decommissioning should increase, while if the structure is donated to an artificial reef program, cost should decrease; thus, the coefficient of the TW variable should be positive and the REEF coefficient should be negative. Structures toppled-in-place or partially removed are expected to cost less than a structure towed to site, and so the TOW coefficient should be positive.

Functional relations for removal costs are shown in Table 9. About half of the variables are statistically significant and most are of the expected sign. Significant variables include the total weight of the structure and operator participation in a reef program. Water depth exhibits a negative coefficient for each of the models constructed, which is contrary to expectation. In Table 9, four models for removal costs are constructed with broadly consistent results. Removal cost are generally increasing with structure complexity and total weight, and decreasing with water depth and disposition. The fixed cost component is reasonably constant across each model specification. In Model II and Model III, the inclusion of the TOW and CF variables improve the model fits but they are not statistically significant. In Model IV, four partially abandoned and toppled-in-place structures are removed from the data set and the models reestimated.

Example. The cost to remove to shore (REEF=0) an eight-pile, four-well, fixed platform (ST=1) in the Central Gulf of Mexico in 210 ft water depth (WD=210) with a total structure weight of 980 t (TW=980) and two pipeline connections (CF=14) is estimated from Table 9 to be

$$\begin{aligned} C_2(s) &= 1{,}029 + 292(1) - 4.8(210) + 0.65(980) + 10.9(14) \\ &= \$\,1.10 \text{ million} \end{aligned}$$

If the structure is donated to a reef program, the expected cost would be $C_2(s)=\$831{,}000$.

J. Constr. Eng. Manage., 2006, 132(3): 249-258

Table 10. Site Clearance and Verification Cost and Operational Statistics in the Gulf of Mexico—Clearance (CL), Verification (V), and Clearance Verification (CV) (1997–2001)

Parameter (unit)	J(FP, CL)	J(CAIS, CL)	J(FP, V)	J(CAIS, V)	J(FP, CV)	J(CAIS, CV)
ND (day)	6.2	1.7	10.1	2.6	16.3	4.3
TD (day)	4.6	1.4	5.8	1.9	10.4	3.3
SR	—	—	4.7	1.4	4.7	1.4
SU	—	—	3.1	1.2	3.1	1.2
GR	2.3	0.8	—	—	2.3	0.8
GU	0.7	0.4	—	—	0.7	0.4
N		12.2	95	2.8		15.0
WD (ft)	110	62	110	62	110	62
AGE (year)	17.3	18.9	17.3	18.9	17.3	18.9
C_3 ($/job)	28,630	9,610	44,341	11,850	72,971	21,460
C_3/ND ($/day)	4,618	5,653	4,390	4,938	4,504	5,234

Note: Clearance (CL) operations are performed with a heavy duty trawl net and verification (V) operations are performed with a standard shrimper net. Clearance and verification (CV) operations combine the clearance and verification services. Data adapted from Kaiser et al. (2005).

Site Clearance and Verification Cost Estimation

Operational Requirement

Vessels service platforms to transfer supplies and personnel to and from shore bases. Tires, commonly used as fenders on service vessels and platforms, are occasionally lost during contact, and supplies may be dropped overboard during transfer. Materials may also be lost during construction and maintenance, and since moorings fail periodically, anchors and ground tackle (chain, cable) are occasionally left on the seafloor. Site clearance and verification is the process of eliminating or otherwise addressing potentially adverse impacts from debris and seafloor disturbances. For clearance purposes, all abandoned well and platform locations in water depth less than 300 ft (91 m) must be cleared of all obstructions present as a result of oil and gas activities.

Site Clearance and Verification (SC&V) Cost Statistics

Data to estimate SC&V costs was compiled from 300 job reports performed by B&J Martin, Inc., in the Gulf of Mexico from 1997 to 2001 (Kaiser et al. 2005).

In Table 10, operational statistics for verification (V), clearance (CL), and clearance and verification (CV) operations are broken out for fixed platform (FP) and caisson (CAIS) jobs. The amount of time involved to clear a site depends on the amount, size, and type of debris present, the method of removal and equipment available to perform the operation, and the water depth. Older and more complex structures, especially development and manned production facilities, normally have more targets that are identified and removed, and so the age of the structure and its configuration type is expected to play a factor in the cost of the operation.

Let SR, SU, GR, and GU denote the number of repairable and unrepairable shrimper and Gorilla nets, respectively, damaged by trawling. These are charged by the contractor and are recorded in the job report. The number of shrimper and Gorilla nets damaged across sites previously occupied by platforms is greater than caisson sites by a factor of three. The number of items collected (N) provides some indication of the complexity of the task, but since the size, weight, and volume of the debris is not described, the value of enumeration remains somewhat limited; e.g., a tire and a 12 ft long drill string both count as "one" item. For the most part, however, the average number of items collected as a function of structure type behaves as expected—platforms have the most debris and delineation/exploratory wells the least.

For clearance and verification services, the average cost of service range from $21,000 for caissons to $73,000 for platforms. On a day-rate basis, verification services cost about $4,000/day regardless of structure type, whereas for clearance and verification, the average service rates are only slightly higher, and the total cost for verification services is about half the cost for clearance and verification. The cost to clear a caisson or platform using heavy-duty nets with a trawling vessel is on average $10,000–$29,000 per job, or $4,600/day–$5,700/day.

Table 11. Site Clearance and Verification Cost Models

	$C_3(s)=\alpha_0+\alpha_1\mathrm{AGE}+\alpha_2\mathrm{WD}+\alpha_3\mathrm{ND}+\alpha_4 N$					
Job type	α_0	α_1	α_2	α_3	α_4	R^2
J(FP, V)	17,979 (4.3)	642 (4.0)	71 (2.9)			0.15
J(FP, V)	−4,453 (−3.1)	14 (2.8)	5 (2.1)	4,378 (26.2)	84 (2.6)	0.92
J(FP, CV)	6,104 (0.6)	1,648 (4.1)	195 (3.2)			0.41
J(FP, CV)	−3,245 (−0.6)	780 (3.3)	39 (1.2)	2,562 (89.0)		0.83
J(CAIS, CV)	−3,873 (−0.7)	457 (2.4)	269 (3.9)			0.76
J(CAIS, CV)	−9,565 (−5.1)	264 (3.9)	32 (0.8)	5,674 (7.2)		0.97
J(CAIS, CV)	−6,483 (−1.9)			6,280 (6.5)	88 (1.2)	0.93

Note: t statistics are presented in parentheses. Data adapted from Kaiser et al. (2005).

J. Constr. Eng. Manage., 2006, 132(3): 249-258

SC&V Model Results

Site clearance and verification cost for structure s, $C_3(s)$, is described through a linear specification

$$C_3(s) = \alpha_0 + \sum_{i=1}^{4} \alpha_i X_i \tag{3}$$

where X_1=AGE=age upon removal (years); X_2=WD=water depth (ft); X_3=ND=number of days of operation (days); and $X_4=N$=number of items collected from the site. All the variables are numeric.

Regression models that estimate the cost to clear and verify a site are shown in Table 11 according to configuration type and job specification. The strongest correlation of the total cost is with variables that are only known *after* the operation is complete (ND and N), which obviously limit the use of the functional for predictive purposes. There is a positive but weak correlation with the factors AGE and WD. Inclusion of the descriptor variable ND significantly enhances the model fits because of the dayrate basis of the contracts.

Example. The cost to clear and verify a 24-year, eight-pile fixed platform (FP), and a 15-year caisson (CAIS) in 210 ft water depth (WD=210) is estimated from Table 11 to be

$$C_3(\mathrm{FP}) = \$\,6{,}104 + 1{,}648(24) + 195(210) = \$\,86{,}606$$

$$C_3(\mathrm{CAIS}) = \$ - 3{,}873 + 457(15) + 269(210) = \$\,59{,}472$$

If SC&V is expected to take three days for the caisson and seven days for the fixed platform, the cost is estimated as:

$$C_3(\mathrm{FP}) = \$ - 3{,}245 + 780(24) + 39(210) + 2{,}562(7) = \$\,41{,}600$$

$$C_3(\mathrm{CAIS}) = \$ - 9{,}565 + 264(15) + 32(210) + 5{,}674(3) = \$\,18{,}137$$

Conclusions

Decommissioning represents the end of the production life cycle of an offshore structure, when wells are plugged and abandoned, infrastructure is removed, and the site is remediated and cleared of debris. The nature of offshore decommissioning, and the inability to account for all the factors that influence activities, provide the stimulus to develop multidimensional cost functions of the operation. There has been little systematic analysis of decommissioning cost that is publicly available. Most studies rely on engineering assessments performed prior to the operation, or on observed performance in a small set of jobs, rather than the actual occurrence of events. The purpose of this paper was to develop empirical cost functions across each of the three main stages of decommissioning. Site-specific characteristics and the uncertainty associated with the operation drives the variability observed in the relations. The functions developed supplement cost estimates performed by offshore engineers and project managers.

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J. Constr. Eng. Manage., 2006, 132(3): 249-258