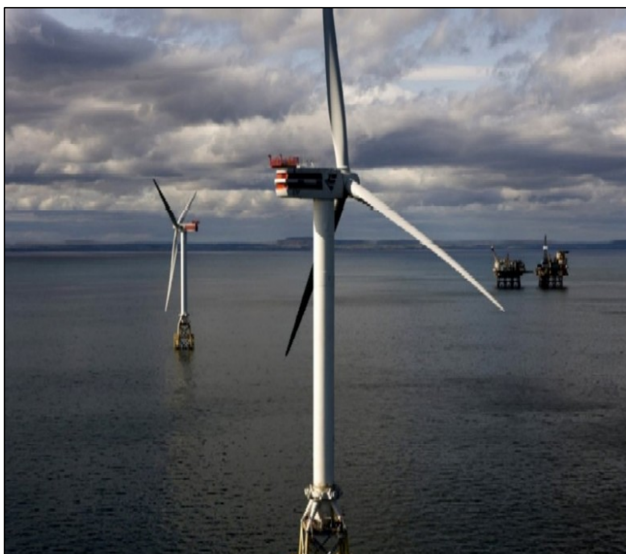
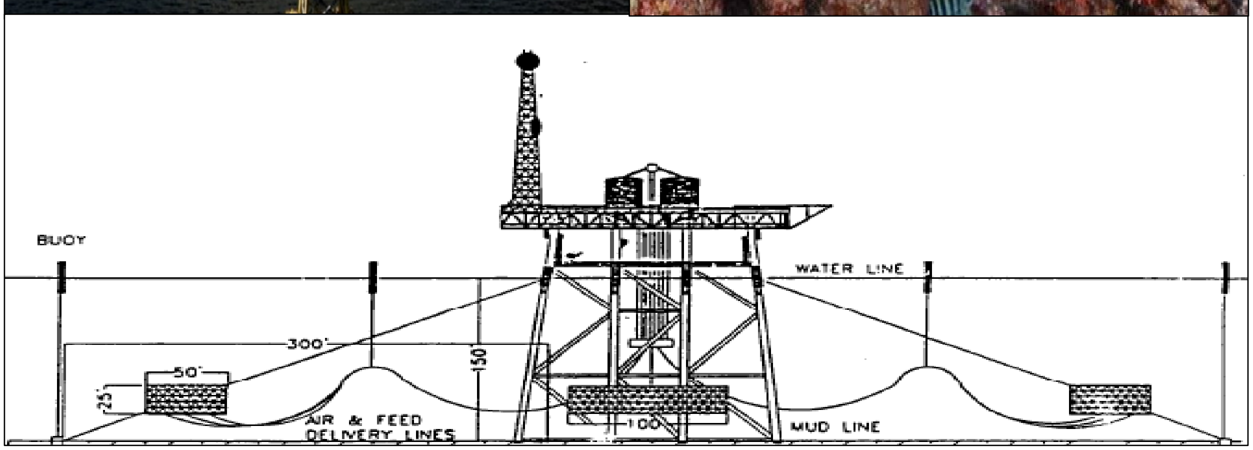
OCS Study
BOEMRE 2011-028

Coastal Marine Institute

Assessment of Opportunities for Alternative Uses of Hydrocarbon Infrastructure in the Gulf of Mexico





U.S. Department of the Interior
Bureau of Ocean Energy Management, Regulation and Enforcement
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

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Assessment of Opportunities for Alternative Uses of Hydrocarbon Infrastructure in the Gulf of Mexico

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ABOUT THE COVER

Sources: Talisman Energy, 2008; National Geographic, 2009; Reggio, 1996.

ABSTRACT

When an operator is granted a lease to develop oil and gas resources on the Outer Continental Shelf in the Gulf of Mexico, they are required to remove structures within one year of the end of production on the lease. There are approximately 3,507 offshore oil and gas structures in the Gulf as of January 2011. Over the next decade, the number of structures is expected to decline by about 1,500, thus, there is a great deal of interest among both regulators and operators in finding new uses for these structures. Currently, most of the offshore structures that have been decommissioned are brought to shore and stored or used for scrap with a small number being reused in new developments. Artificial reef programs in Louisiana and Texas accept a modest number of platforms. The most likely alternative applications are as bases for mariculture or foundations for offshore wind farms. In this report we analyze the relative merits of each of these uses and potential uses based on their technological and economic feasibility. In short, platform based mariculture, while technically feasible, is plagued by economic issues that make it unlikely to be profitable in the near-term, while oil and gas infrastructure is generally not suited for the offshore wind industry due to scale economies and several other technical issues. It is possible that both mariculture and offshore wind could use oil and gas infrastructure in the future, and we discuss the circumstances under which this might occur. We find that only the use of platforms as artificial reefs is a realistic near term destination for existing infrastructure.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

LIST OF FIGURES

Page

LIST OF FIGURES
(continued)

Page

LIST OF FIGURES
(continued)

Page

LIST OF TABLES

LIST OF TABLES
(continued)

EXECUTIVE SUMMARY

When an operator is granted a lease to develop oil and gas resources on the Outer Continental Shelf of the Gulf of Mexico (GOM), they are required to decommission the lease area within one year of the end of production on the lease. Decommissioning involves plugging wells, removing structures, and clearing the seafloor of oil and gas debris. Decommissioning represents a liability to operators and there are often financial benefits for operators to delay decommissioning. As a result, there are several hundred idle structures in the GOM, and the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) has in a recent notice to lessees proposed new regulations on plugging and abandonment and structure removal to require operators to remove structures as they become economically unviable, rather than when the entire lease area stops producing.

There are approximately 3,507 offshore oil and gas structures in the GOM as of January 2011, and over the next decade, about 1,500 structures in the GOM are expected to be removed. Approximately 3,450 structures have been removed since 1973.

The Energy Policy Act of 2005 gave BOEMRE the authority to regulate the use of oil and gas structures for alternative marine and energy applications. Thus, there is a great deal of interest in finding new uses for oil and gas infrastructure. Currently, most of the offshore structures that have been decommissioned are brought to shore and used for scrap with a small number being reused in future applications. The most likely alternative applications for this infrastructure are as bases for offshore mariculture or as foundations for wind turbines. Additionally, oil and gas infrastructure can be and has been, donated to coastal states for use in artificial reef programs.

It is possible that mariculture operators or offshore wind development could turn uneconomic platforms into an asset rather than a liability and may make for their more efficient re-use or removal. It is also possible that their use may make other industries, for example the offshore wind industry, more profitable by providing a plentiful supply of infrastructure, thereby lowering capital costs.

Of the alternative uses for oil and gas infrastructure, only their use as artificial reefs is likely to provide an economically attractive outlet for infrastructure in the future. Several hundred oil and gas platforms have already been donated as artificial reefs to Texas and Louisiana, and although all of the GOM coastal states have active artificial reef programs, not all Gulf states accept platforms.

The prospects for using oil and gas platforms for offshore mariculture operations are limited. Platform-based mariculture is an operation in which high-value fish are raised in net cages in close proximity to a manned offshore platform. The platforms are used as living and storage space and as a base of operations for the culture of the fish. Offshore oil and gas structures would make suitable platforms for offshore mariculture operations; however, the high risks, high capital and labor costs, and competition from capture fisheries make platform-based offshore mariculture a risky and likely unprofitable venture. Therefore, offshore mariculture is unlikely to be a significant market for oil and gas platforms unless significant changes in market conditions occur. If the price of certain species of wild-caught fish increases, the price of transporting fish from Asia increases, or the technology for offshore mariculture develops further, then the offshore mariculture industry in the U.S. may develop and provide a market for some platforms.

Offshore wind power provides a potential alternative use for oil and gas infrastructure. Offshore wind power also faces economic hurdles that are likely to impede the development of the industry, and there are basic difficulties in using oil and gas infrastructure in the offshore wind industry. Offshore wind farms need to be sited carefully; therefore, oil and gas platforms could not be used in place and would need to be moved to new locations; this would eliminate much of the cost associated with decommissioning, but could still create a market for jacketed foundations. However, offshore wind farms also need to be composed of dozens of wind turbines with specific site and operational conditions that require an assembly-line approach for foundation placement and turbine installation. This would require developers to collect dozens of similar jackets, store them onshore, and then install at a later date.

We first review decommissioning and artificial reef programs in Louisiana and Texas. We then describe the impacts of the 2005 hurricane season on the Louisiana Artificial Reef Program. We discuss the platform-based mariculture industry and model its economic profitability through net present value analysis. We offer a discussion of offshore wind power, including a comparison of its development in the U.S. and Europe, an overview of its costs and benefits, and a discussion of the tradeoffs associated with its regulation. The report concludes with a non-technical commentary on the problems and potentials of using oil and gas infrastructure in the wind industry.

1. USE OF OFFSHORE PLATFORMS FOR ARTIFICIAL REEFS

In this chapter, we provide background information for understanding this practice. We begin by describing the types of offshore production facilities and their lifecycle. We outline the regulatory environment surrounding decommissioning and discuss the decision matrix governing abandonment and the process of decommissioning. We conclude by describing the factors governing the costs of decommissioning.

1.1. National Fishing Enhancement Act

Offshore platforms have been an important component of both the recreational and fishing industries in the Gulf of Mexico (GOM) and have long been recognized as de facto artificial reefs (Dauterive, 2001; Harville, 1983; Reggio, 1989). Shortly after an offshore structure is installed, sessile invertebrates such as barnacles, oysters, mussels, and sponges attach to the underwater frame, attracting mobile invertebrates and fish species, which in turn attract larger fish that feed upon them, and so on, forming a highly complex and interrelated food web. Once an offshore structure is removed to shore, however, the artificial reef habitat is eliminated and the associated biological community is affected. Various platform faunal studies have been performed over the years (e.g., Driessen, 1985; Stanley and Wilson, 1991; Carr and Hixon, 1997), but it is still a matter of scientific debate the degree to which artificial reefs attract and produce fishery resources. For a good review of the "attraction versus production" debate, see (Pickering and Whitmarsh, 1997).

Since 1947, when offshore production in the GOM first began, over 2,200 structures have been removed (Figures A.1 and A.2). Over the past decade, 141 structures per year on average have been removed. As the number of removals began to escalate in the mid-1980s, the need to preserve the diverse ecosystems created by the offshore structures became evident (Dauterive, 2001; Reggio, 1987; Reggio, 1989).

The first major attempt by the U.S. government to create an artificial reef program was undertaken in 1972 when the Department of Commerce authorized the release and sinking of World War II Liberty ships for the construction of artificial reefs. The first offshore structure reefed in the GOM occurred in 1979, when a 2,120 ton subsea production system was towed from Louisiana to a site off western Florida. Over the next few years, several additional structures were moved to various sites across the Gulf. Responding to this new activity, Congress passed the National Fishing Enhancement Act (NFEA), and in 1984, the NFEA (Title II of Public Law 98-623) was signed by President Reagan to "promote and facilitate responsible and effective efforts to establish artificial reefs… constructed or placed for the purpose of enhancing fishery resources and commercial and recreational opportunities."

The NFEA consolidated several decades of local and state laws (Meier, 1989; Murray, 1994; Stone, 1985) and directed the National Marine Fisheries Service to develop the National Artificial Reef Plan to serve as a guide to state artificial reef programs. The NFEA mandated the Secretary of Commerce and other support groups to develop a long-term plan for siting, constructing, permitting, installing, monitoring, managing, and maintaining artificial reefs within and seaward of state jurisdictions.

1.2. Types of Offshore Facilities

In the federally[1] regulated Outer Continental Shelf (OCS) of the GOM, nearly 4,000 structures are currently in use in the production of oil and natural gas. The types of structures and range of configurations vary widely, but shallow-water structures – defined as structures in water depth less than 1,000 ft – generally consist of three main elements:

1) A tubular steel structure, called the template or jacket, which extends from the seafloor to above the waterline and is used to support the deck and topsides equipment;
2) Steel pipe piling driven through the jacket legs into the seafloor to provide the platform foundation; and
3) One or more deck sections placed on top of the jacket to hold the drilling and processing equipment, heliport, quarters, and related infrastructure.

In addition to these three basic elements, offshore structures may also contain, depending on the function of the structure,

4) Conductors, which are used to conduct the oil and gas to the surface;
5) Topsides equipment, such as compressors, cranes, drills, heat exchangers, meters, power generation units, pumps, separators, scrubbers, tanks, etc.; and
6) Bottomsides equipment, such as cable, manifolds, pipelines, flowlines, risers, umbilicals, wellheads, etc.

Offshore development strategies 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 typically employ caissons (Figure A.3), well protectors and fixed platforms (Figure A.4), and subsea completions (Figure A.5).

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 are 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. Production from caissons, well protectors, and subsea completions is sent to processing facilities on a fixed platform prior to being transported to shore. 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 A.1.

In the deepwater GOM defined as water depth greater than 1,000 feet, compliant towers, spars, subsea systems, tension-leg platforms, and floating production units are employed (Figure A.6).

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[1] The federally regulated waters of the GOM begins seaward three nautical miles offshore the Louisiana, Alabama, and Mississippi shorelines, and nine nautical miles from the Texas and Florida shorelines, and extends 200 miles through the Exclusive Economic Zone.

The number of deepwater units is relatively small (Table A.2), but currently contribute more than 70 percent of the total oil production in the GOM. Fixed platforms have an economic water depth limit of about 1,500 ft, while compliant towers are viable for water depths ranging between 1,000-3,000 ft. Tension leg platforms (TLPs) are frequently used in 1,000-5,000 ft water depths. Spars, semisubmersible production units, floating production, storage, and offloading systems, and subsea wells are used in water depths ranging up to and beyond 10,000 ft (Baud et al., 2002).

Structures are installed to produce and process hydrocarbons, and when the time arrives that the cost to operate a structure 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 abandonment. When the operating cost of a structure equals the income from production, the economic limit is said to be reached, and a decision to abandon the structure and shut-in production is made.

1.3. Stages of Oil and Gas Development

During the life cycle of a field, and depending upon the prevailing and expected future economics, technologic development, strategic objectives, political trends, and contract terms, an operator has to make many short-term operational and long-term strategic planning decisions. Five primary options exist at any point in time:

- Produce. Hold the asset, produce, and manage the declining reserves.
- Invest. Invest in the asset to maintain or increase production.
- Divest. Sell all or a portion of the working interest ownership.
- Abandon. Stop production.
- Decommission. Remove the asset in accord with regulatory requirements.

1.3.1. Produce

Early in the life of a field after the development wells have been drilled, the field is produced according to equipment capacity and operating constraints. Capital expenditures decline quickly after development is complete, and after the field begins to flow, gross revenues turn positive. Once the exploration and development cost of the investment have been borne, the variable costs of production are usually fairly small, and the operator needs only to produce to achieve cash flow. The cumulative net cash flow breaks even at payout after which the cash flow remains positive until such time that additional capital investment is required.

1.3.2. Invest/Divest

Investment will alter the production profile and will typically extend the life of the asset. If a field requires major new investment such as significant workovers or the introduction of secondary techniques to maintain production, the field is likely to be considered a candidate for divestiture or abandonment. Operators regularly “carve up” assets and sell or subject them to various joint venture/farmout type arrangements throughout the life cycle of the field. This is sometimes referred to colorfully as an asset “moving down the food chain.” Companies buy producing properties and then implement a comprehensive program to increase production, typically involving drilling new stepout or infill wells and recompleting existing wells. Companies specializing[2] in marginal production focus on operating mature fields in a geographic region where they already own infrastructure. Divestment frequently acts to extend lease life, recover greater quantities of hydrocarbons, and ultimately, delay the "expected" abandonment of the structure.

1.3.3. Abandon

Structures are installed to produce hydrocarbons, but at some point in time the cost of operation will exceed the income from production, and the structure will exist as a liability instead of an asset. When the production revenues of the asset approach the operating costs, the structure will be abandoned, and depending on lease conditions and operator preferences, decommissioning will follow. When a lease no longer produces paying quantities, the operator has one year to remove all the structures on the lease.

1.3.4. Decommission

The basic aim of decommissioning is to render all wells safe and remove most, if not all, surface/seabed signs of production activity. Decommissioning represents a liability as opposed to an investment, and so the pressure for an operator to decommission a structure is not nearly as strongly driven as installation activities. Delaying decommissioning frequently has economic value for the firm since it defers expenditure, while allowing the deferred funds to be invested in productive (profit-generating) activities. Federal regulations require that all wells and offshore structures on a lease be completely removed within one year after production on the lease ceases.

Simple structures in shallow waters can be removed relatively easily and inexpensively. Caissons are just big pipes in the ground, and so a lift vessel or stiffleg in conjunction with a diving crew is usually sufficient to cut it, pull it, and put it on a cargo barge. Braced caissons, well protectors, and fixed platforms are more complex structures that require greater planning and preparation to ensure the health and safety of workers while minimizing the environmental impact and operational cost of removal. Generally speaking, as the structure size, complexity, and water depth increases, the removal process becomes more complex and costly, creating greater risks to the safety of workers and incurring additional costs to the operator.

1.4. Regulatory Requirements

The federal waters of the GOM are divided into three large planning areas labeled the Western, Central, and Eastern Gulf of Mexico (Figure A.7). Each planning area is subdivided into smaller area codes called area blocks, which in turn are divided into numbered blocks. A block is normally a nine square mile area consisting of 5,760 acres and is the smallest unit that can be leased for oil and gas exploration. Lease terms and dimensions vary with the time of the auction and the location of the lease, but most give the leaseholder the exclusive right to explore for oil

[2] Operators can manage marginal assets at a profit in part due to their lower overheads, lower expected rate of return, scale economies, and other strategic factors; e.g., the operator may be a subsidiary of a construction company which serves to feed abandoned structures to the parent for removal.

and gas for a period of 5, 8 or 10 years depending on water depth. The terms of the lease extend for as long as the lease is productive or development/drilling activities are progressing.

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, while the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) is responsible for structures in federal waters. The general requirements for decommissioning in federal waters are specified in 30 CFR §250.1703 (*Federal Register*, 2002) 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. Typically, a lease terminates when production on the lease ceases, but special approval may be granted to maintain structures on a non-producing lease.

1.4.1. Legislation

All five coastal states bordering the Gulf of Mexico have active artificial reef programs, but only Louisiana and Texas rely almost exclusively on oil and gas structures for reef material. Since the inception of the Louisiana and Texas Artificial Reef programs (Wilson and Van Sickle, 1987; Shively et al., 2003; Stephan, 1996), nearly 200 offshore structures have been accepted as artificial reefs. Alabama, Florida, and Mississippi also have prolific reef programs, but have accepted far fewer offshore structures because most of the Gulf's oil and gas infrastructure lie offshore Louisiana's coast in the Central GOM (recall Table A.1). A handful of structures lie east of the Mississippi river in waters off Mississippi and Alabama, and a few hundred are scattered off the Texas coast. The geographic concentration of platforms means that most structures will be towed to the nearest port or scrap yard, while further offshore, reefing will only be economic when a structure is located in close proximity to an artificial reef planning area. Onshore communities across Louisiana and Texas are also familiar with oil and gas activities, and there is generally more widespread community acceptance[3] for the energy industry and rigs-to-reef programs, making placement easier and less acrimonious.

1.4.2. Permit Agencies

The BOEMRE requires that within one year of an OCS lease termination, the lessee remove the structure and clear the area of obstructions. The BOEMRE will waive these requirements to accommodate conversion of a structure to an artificial reef provided that (1) the structure does not inhibit future development opportunities, (2) the resulting artificial reef complies with the Corps of Engineers permit requirements and procedures outlined in the National Artificial Reef Plan, (3) a State fishing management agency accepts liability for the structure, and (4) the structure meets all applicable BOEMRE engineering, stability, and environmental reviewing standards found in the BOEMRE Rigs-to-Reefs policy addendum. Two agencies are involved in issuing permits for artificial reefs in federal waters: the U.S. Army Corps of Engineers (COE) and the U.S. Coast Guard (USCG). A permit to site a structure as an artificial reef is granted by the COE under Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403). The COE

[3] Reggio has estimated that 70 percent of all fishing trips off the coast of Louisiana were destined for one or more offshore structures (Reggio, 1987).

reviews the operation, inspects the materials, and then issues the appropriate permit or makes recommendations to improve the permit application.

1.4.3. Aids to Navigation

Local Coast Guard districts are responsible for the safety of vessel traffic in their geographic areas and have the authority to dictate aids to navigation for obstacles in the water. Artificial reefs are classified as obstructions to navigation and must be marked in accordance with USCG District guidelines. In general, three factors determine the marking requirements for artificial reefs: (1) Distance from navigation fairways, (2) Diameter of the reef complex, and (3) Minimum clearance between the top of the reef structure and the water surface. The Coast Guard District Commander determines on a case-by-case basis if markers are required and their type[4], number, and description (Wilson and Van Sickle, 1987). For example, the 8th Coast Guard District, with jurisdiction from western Florida to the Texas-Mexico border, generally requires a minimum of 85 ft clearance above the obstruction in order to be exempt from maintaining lighting requirements.

1.5. Decommissioning Decision Tree

Decisions about when and how a structure is decommissioned involve issues of environmental protection, safety, cost, and strategic opportunity. The factors that influence the timing of removal as well as the manner in which a structure is disposed are complicated and depend as much on the technical requirements and cost as on the preferences established by the contractor and the federal regulations (Figure A.8).

The decision to reef a structure is made within the context of alternative decommissioning options. Cost is a primary decision factor. If removal option X is expected to have cost $E[C(X)]$, then option A will be preferred to option B if $E[C(A)] < E[C(B)]$, all other things being equal. Other factors that play a role in decision making include the expected duration of the operation, perceived risk, past experience, and historical relationship between the operator and state.

Oil and gas processing equipment and piping are sent to shore to be refurbished and reused, where possible, sold for scrap, and/or disposed of in an approved landfill. Piling and conductors are typically broken down and recycled, while opportunities for large scale or wholesale reuse of topsides equipment is limited due to the effects of age, corrosion, and changing technical standards (Terdre, 2000; Van Voorst, 1999). Material such as braces, bridges, heliports and miscellaneous steel are typically stored onshore for reuse and scrap.

Deck and jacket structures have more options for disposal. The deck and jacket may be scrapped onshore, moved to a new location and reinstalled, or converted to an artificial reef. Onshore disposal is the most common in the GOM, occurring in about 80 percent of structure removals

[4] General guidelines follow: if the obstacle is greater than 61 m (200 ft) in depth, aids to navigation are not required; if the obstacle is from 26-61 m (85-200 ft) in depth, unlighted buoys are required; if the obstacle is from 11 m (35 ft) to protruding through the surface, lights or lighted buoys and foghorns are required.

since state rig-to-reef programs were initiated. Decks and jackets are stored[5] onshore in fabrication and scrap yards and offshore on producing leases as idle iron (Kaiser and Pulsipher, 2007a). Most structures will be broken down, sold for scrap, and recycled. Decks are generally easier to reuse than jackets, and are also easier/cheaper to scrap because of their configuration, but they are rarely used as reef material. Jackets, on the other hand, are ideally suited for artificial reefs because of their size, shape, design, and density (Harville, 1983; Reggio, 1987). The openness of a jacket structure allows for water circulation and easy mobility for fish, attracting not only bottom dwelling fish, but also mid- to top-water dwellers. Steel jackets are among the most stable and durable[6] reef material available.

Artificial reefs are a decommissioning option created within the context of the decommissioning process and a number of excellent case studies on rigs-to-reef projects are available; e.g., see (Hakam and Thornton, 2000; Kasprzak, 1999; Parker and Henkhaus, 1989; Perry et al., 1998; Quigel and Thornton, 1989). For a more comprehensive overview of the technical requirements of decommissioning, see (Manago and Williamson, 1997; Pulsipher, 1996; National Research Council, 1996), and for a broader discussion of rigs-to-reef program and decommissioning, see (Baine, 2001; Dauterive, 2001; Hamzah, 2003; MacDonald, 1994; Pulsipher and Daniel, 2000; Reggio, 1989; Schroeder and Love, 2004).

1.6. Stages of Decommissioning

1.6.1. Planning and Permitting

The engineering planning phase of decommissioning typically 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 are sent to the site to assess the work requirements, and the project management team will report on the options available to the operator, including the scope of work that needs to be performed and how best to prepare the bid. Following project engineering and cost assessment, federal and state regulatory permits for well plugging and abandonment, pipeline abandonment, structure removal, and site clearance verification must be obtained from the BOEMRE (Manago and Williamson, 1997; Pulsipher, 1996).

1.6.2. Plug and Abandonment

The purpose of plug and abandonment (P&A) is to prevent flow of the formation fluid and stabilize the wellbore and its associated annuli until geologic forces can re-establish the natural barriers that existed before the well was drilled. P&A isolates hydrocarbon zones, protect freshwater aquifers, and prevent migration of formation fluids within the wellbore or the seafloor. Isolation of the hydrocarbon-bearing intervals and uncemented annuli is critical to

[5] Only a small percentage of structures in inventory, perhaps 10-20 percent for decks, and less than 10 percent for jackets, are refurbished and reused.

[6] Many manmade reefs have historically utilized “materials of opportunity” such as boxcars, tanks, ships, tires, construction rubble, oyster shell, etc. Other than ships, most of these materials have little long-term success because they are easily broken up and moved by storms.

successful abandonment. P&A activities essentially involve setting various cement plugs in wells to ensure downhole isolation of hydrocarbon zones which prevents the migration of formation fluids within the wellbore or to the seafloor. Plugging and abandoning wells 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.

1.6.3. Preparation

The structure is prepared for removal and an inspection is made to determine the condition of the structure and identify potential problems with the salvage. 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 performed. 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 BOEMRE regulations. Equipment and other metallic debris are sent onshore to recycle or scrap, while non-metallic debris is sent as waste to a landfill.

1.6.4. Pipeline Abandonment

A pipeline may be abandoned in place if it does not constitute a hazard to navigation, commercial fishing operations, or unduly interferes with other users in the OCS. Pipelines abandoned in place need to be flushed, filled with seawater, cut, and plugged with the ends buried at least 3 ft (1 m) below the mudline. Most pipelines in the GOM are abandoned in place and very few complete removals have been performed (Pulsipher, 1996).

1.6.5. Structure Removal

The removal of the topside facilities, deck, conductors, piles, and jacket is the core of the decommissioning project and typically the most expensive stage (Kaiser et al., 2003).

Deck Removal

The deck is normally cut from the jacket using torches. The deck is then lifted and placed on a cargo barge (Figure A.9), secured, and returned to shore for scrap or reuse. The interior of the piling is then cleared using water jets to remove the mud from within the platform legs so that the explosives (or other cutting device) can be lowered 15 feet (5 m) below the mudline.

Pile and Conductor Removal

Conductors, casing string, and piling are cut at least 15 ft (5 m) below the mudline, pulled, and removed. Conductor severing and removal may take place as part of P&A activity or during the structure removal operation. Mechanical casing cutters, abrasive water jets, or explosives are used to cut conductors at the designated elevation (Kaiser et al., 2004). Piles are frequently severed using explosives, although abrasive water jet technology is also employed up to 250 ft. The explosives technician prepares and loads the charges into the legs and conductors (Figure A.10), the derrick barge is backed off a safe distance, and the explosives are detonated in accord with federal regulations (Figure A.11). Piling and conductors are pulled using the derrick barge crane (Figure A.12).

Jacket Removal

After the conductors and piles have been removed, the jacket structure is lifted out of the water (Figure A.13) and welded to a materials barge for transport to shore or a reef site (Figure A.14). The jacket can also be floated and towed to a reef site. If the jacket is to be reefed, several options are available. In some cases, the jacket is toppled-in-place after the piling has been cut (Figure A.15), while in other cases, the jacket is cut in half in the water column and the top-half of the structure is placed on the seabed near the bottom half (Figure A.16). A structure "toppled-in-place" proceeds much like a complete removal, except that after the piles are cut and removed the structure is pulled over and placed on its side on the seafloor. 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[7] and placed next to the base or removed to shore.

1.6.6. Site Clearance and Verification

The last stage in decommissioning is site clearance and verification. Site clearance is the process of eliminating, or otherwise addressing, potentially adverse impacts from debris and seafloor disturbances, while verification is used to ensure that the site is clear of obstructions. According to BOEMRE regulations, all abandoned well and platform locations in water depth less than 300 feet must be cleared of all obstructions present as a result of oil and gas activities. After the jacket has been removed, the site is cleared with a trawling vessel or divers deployed with scanning sonar, and then clearance is verified with a trawler. Specialized, heavy-duty trawling gears with reinforced mesh, commonly known as "Gorilla Nets," are used in the operation. The nets are dragged over the seafloor in four directions to provide 100 percent coverage of the area (Figure A.17). Waivers for site clearance and verification are sometimes granted for structures reefed in place.

1.7. Factor Description

If a structure is proposed for reefing, an estimate of the costs of alternative decommissioning options (reefing, scrapping, etc.) is made before decommissioning is performed and a cost savings to the operator from reefing is determined. The operator then generally donates half of the cost savings to the state. As a result, the greater the cost savings are the larger the donation to the state.

A number of factors impact the cost of converting a rig into a reef, and subsequently, the cost savings associated with reefing. The size, location, water depth, method of removal, and proximity of the platform to the permitted reef site all affect the cost of the operation.

[7] Because of the prohibition on using explosives in the water column, abrasive or mechanical cutters are used to cut the jacket at a safe navigational depth specified by the U.S. Coast Guard (typically 85 ft).

Environmental, engineering, and market conditions introduce additional uncertainty and can also have a significant impact on the operation. It is difficult to enumerate and measure all the characteristics that might be important, but in practice, it is only necessary to consider a set of factors that describe the essential elements of the process.

1.7.1. Complexity

The size and weight of a structure are important parameters since they determine the size and type of construction equipment required in the operation. The derrick barge (DB) required is determined by the water depth in which the DB can operate and the lift capacity of the cranes. The minimum DB required to remove a structure is determined by the maximum load weights expected during the operation, which in turn, is determined by the weight of the deck and jacket and the cutting methods employed. In shallow waters, the deck is normally the heaviest lift, while in deepwater, the jacket weight normally exceeds the deck weight. Decommissioning cost generally increase with the complexity of the structure and water depth at the site (Kaiser et al., 2003), and so we would suspect that the average donation for 3- and 4-pile structures would be less than 8-pile structures, for all other things equal.

1.7.2. Location

The location of a structure is determined by its latitude and longitude coordinates. Location is an important factor since it determines the distance to the onshore support facility, water depth, and distance to the nearest reef site. Distance to shore is an important variable since as the distance increases so does the transportation and related service costs. Tow distance to the nearest reef site is an important variable, since as the tow distance increases, the cost savings associated with reefing would be expected to decline. In water depth less than 100 ft, it is almost always more cost effective to dispose of the structure onshore rather than to transport the structure to a distant reef site. For large platforms in deep water, partial removals and toppling-in-place options are more frequently applied. Structures towed to site are expected to contribute less than the topple-in-place and partial removal option due primarily to the additional expense of towing. Structures towed to site are also expected to have a greater probability of cost overruns since the owner is usually more exposed to weather and other delays.

1.7.3. Water Depth

Water depth is an important characteristic in offshore operations since increasing water depth requires the size and weight of a structure to increase, increasing the cost of decommissioning and reducing operational flexibility. Diving operations become more expensive because of diver restrictions on the amount of time underwater, activities are more exposed to weather conditions, etc. The USCG maintains requirements on the minimum clearance between the top of a reefed structure and the water surface, and so the minimum water depth for structures converted to reefs generally range between 80-90 feet.

1.7.4. Removal Method

A structure donated as an artificial reef is either towed to site, toppled-in-place, or partially removed. The cost of a partial removal relative to the topple-in-place option depends upon site-specific conditions. In a partial removal, the jacket is cut in the water column, while the piles are left in place. Cutting in the water column necessitates the use of mechanical and abrasive cutters and, frequently, the use of divers, which generally cost more and creates greater risk to human safety[8] than explosive techniques. However, nonexplosive water column severance is generally more environmentally friendly than a below mudline explosive cut. The direction of cost savings and risk is determined by engineering considerations, the experience of the contractor, and the success of the operation.

1.7.5. Exogenous Events

Offshore operations are highly sensitive to the weather/ocean environment and can suffer economic losses because of adverse conditions. Wind, waves, current, and weather impact operations throughout the year, especially during the winter season, November 30 - March 1, when drilling, construction, and deconstruction activities are particularly at risk. Weather may delay the operation or require the crew to demobilize to shore. Technical complications and other conditions may also delay operations; e.g., the use of explosives requires the water column and general vicinity of the structure to be clear of mammals and sea turtles prior to detonation. Market conditions, and the demand for and supply of liftboats, DB spreads, cutting spreads, and diving support vessels influence not only the cost of the service but also the time when the operation commences.

1.7.6. Tow Distance

Tow distance to the nearest reef site is an important variable, since as the tow distance increases, the cost savings associated with reefing declines. Structures towed to site are expected to contribute less than the topple-in-place and partial removal option due primarily to the additional expense of towing. Structures towed to site are also operationally more risky since the owner is more exposed to weather delays and other delays.

1.7.7. Scale Economics

Operators attempt to reduce the cost of decommissioning through scale economies. By bundling structures in a group and servicing the group as a unit, scale economies can frequently be achieved. The cost to decommission a group of structures as a unit is typically less than for separate operations due to savings from mobilization, shared expenses, and operational efficiencies.

[8] Worker exposure to low-level risks over long periods is generally tolerated in offshore construction activity, but significant efforts are taken to avoid high-level, short-term risks.

2. LOUISIANA ARTIFICIAL REEF PROGRAM

The Louisiana Artificial Reef Program (LARP) is the largest rigs-to-reefs program in the world, and is unique in its almost exclusive use of oil and gas structures for reef construction. In 1986, Louisiana became the first state to create an artificial reef program under the guidance of National Fishing Enhancement Act and authorization of the Louisiana Fishing Enhancement Act. Between 1987 and 2003, 120 structures worth over $20 million were donated benefiting both the petroleum industry and the state. Although the proportion of rigs donated as artificial reefs is a small fraction of the total number of oil platforms decommissioned each year, these artificial reefs are important for fish reproduction and attraction.

In this chapter we review the regulatory structure of LARP, discuss the nature of the cost savings associated with reef donation, and construct regression models that quantify the donation amount.

2.1. Background

2.1.1. Donation Requirements

Operators that donate a platform as an artificial reef can often lower the cost of decommissioning below the cost to bring the platform to shore for disposal, but many factors are involved in determining the cost of decommissioning a rig or turning it into a reef, and subsequently, the cost savings associated with reefing. The usual practice is for the state and operator to obtain a third-party estimate of the cost for removal alternatives *before* decommissioning is performed, and from these estimates, the donation amount is negotiated with the cost savings split between the operator and state. Formally, if the expected cost to remove a structure to shore is denoted $\mathrm{E}[C(Shore)]$, and the expected cost of reefing is denoted as $\mathrm{E}[C(Reef)]$, then the expected cost savings are estimated as the difference $\mathrm{E}[\Delta]$:

$$\mathrm{E}[\Delta] = \mathrm{E}[C(Shore)] - \mathrm{E}[C(Reef)].$$

If the expected cost savings are large and positive, it is likely the structure will be reefed, with operators donating one-half of the expected savings into the Louisiana trust fund for administration and related activities. If the expected cost savings are small, or negative, it is unlikely the structure will be reefed. A risk premium is usually implicit in the decision, since the donation amount is determined *prior to* the operation, and there is no way for the operator to adjust the values if unforeseen circumstances[9] occur.

2.1.2. Liability

BOEMRE regulations provide that a platform operator may be released from removal obligations in the federal lease instrument if a state agency responsible for managing fisheries resources will accept liability. The Louisiana Fishing Enhancement Act of 1986 established the state of

[9] Decommissioning operations are usually performed on a turnkey (lump sum) basis, but the contractor may be required to perform "extra work" not covered in the scope of work and not included in the base bid. The operator accepts the risk of cost overruns and does not share or pass through this expense.

Louisiana as the permittee for artificial reefs developed under the program's jurisdiction and appointed the Department of Wildlife and Fisheries as agent for the state. The state assumes ownership of the structure after being donated to the reef program and is responsible for the cost of buoy construction and replacement, operation, and liability in perpetuity. The donor and other participants constructing a reef under NFEA and Act 100 are absolved from liability provided the terms and conditions of the reef permits are met.

2.1.3. Artificial Reef Planning Areas

Louisiana has designated nine approved sites for the disposition of artificial reefs (Figure B.1, Table B.1). These areas were identified by various user groups and employed both exclusion and inclusion mapping techniques (Wilson and Van Sickle, 1987). First, areas inappropriate for reef development were identified. This process, known as "exclusion mapping," eliminated areas due to navigation fairways, pipeline corridors, military zones, live bottom areas, bottom type and hydrological conditions, and commercial fishing usage. Geologic and man-made features such as faults, gas pockets and rents, sediments of low bearing capacity, irregular and steep seafloor topography, active and relict channels, scarps, salt diapers, natural reefs, pipelines, platforms, subsea production facilities, and unstable areas were identified and assessed from data collected through various geophysical survey features. When exclusion mapping was completed, a series of public hearings were held across south Louisiana to outline the plan and solicit public input where reefs should be located (Kasprzak, 1998). Inclusion mapping identified the use patterns of recreational fisherman, commercial fishermen, sport divers, menhaden and shrimp fisheries. As a result of the hearings and public input, nine planning areas were selected for artificial reef development.

Louisiana has a deepwater planning area in waters greater than 400 ft. Under the current policy, BOEMRE does not allow reefing outside of planning areas and established Special Artificial Reef Sites (SARS).

2.2. Descriptive Statistics

2.2.1. Structure Donation

The number of structures donated to LARP and donation amounts by year are shown in Table B.2. From 1987-2003, 117 structures were donated to LARP – 63 3- and 4-pile jackets, 54 8-pile jackets, one barge, one tug, and one deck. Ten of the 117 structures donated to the program were destroyed by hurricanes. As of May 2004, LARP's trust fund has accrued \$20.8 million (M) for the administration and related activities of the program. The number and amount of donations vary with time, and over the past decade, about eight structures have been donated per year at a total annual donation of \$1.37 million, or \$169,000 per structure, on average.

2.2.2. Program Statistics

In Table B.3, the average donation amount per structure and per pile is shown according to removal method and structure type. From 1987-2003, 80 structures were towed to location, 29 were toppled-in-place, and 8 structures were partially removed. Partially removed and toppled-in-place structures were aggregated in the category "not towed." The average donation for a structure towed to site is $117,000 versus $233,000 for structures not towed,[10] with $21,000 and $37,000 the average donation per pile, respectively. Structures towed to site are expected to contribute less than the topple-in-place and partial removal option due in part to the cost[11] to tow the rig to location. For structures reefed in place, waivers for site clearance and verification may be granted further enhancing the cost savings of these operations.

Decommissioning cost generally increases with the complexity of the structure and water depth at the site (Kaiser et al., 2003), and so we would suspect that for 3-pile and 4-pile structures the donation will be less than for 8-pile structures, and indeed, this is generally confirmed by the data. For structures towed to location, the average donation per structure increases from $47,000 (3-pile) to $97,000 (4-pile) to $150,000 (8-pile). For structures toppled-in-place and partially removed, the trends are subverted, from $450,000 (3-pile) to $246,000 (4-pile) to $212,000 (8-pile), probably due to the small sample size and more diverse nature of the removal methods. On a pile-normalized basis, economies of scale are evident across the 4-pile and 8-pile categories since the donation per pile decreases with the number of piles.

2.2.3. Operator Involvement

ChevronTexaco owns the most infrastructure in the GOM, and so it is not surprising that they have also donated the most platforms to LARP. Six operators – KerrMcGee, CNG, ExxonMobil, Apache, Forest Oil, and Hunt – have each donated six or more structures (Table B.4). ChevronTexaco and Forest Oil have contributed more than one-third of the total program donations. Thirty-seven operators in total have participated in the program, with 15 operators contributing over 75 percent of the total donation.

2.2.4. Capture Probability and Removal Method

The percentage of structures reefed as a function of water depth is computed as the ratio of the total number of structures reefed divided by the number of well protectors (*WP*) and fixed platforms (*FP*) removed over the time horizon 1987-2002:

$$\mathrm{P(Reef)} = \frac{\text{Number structures reefed}}{\text{Number structures removed}}.$$

Caissons are generally not considered candidates for reef material, and so only well protectors and fixed platforms are counted. The time horizon for enumeration begins from the inception of LARP and the CGOM planning area is used as a geographic proxy of the pool of candidate structures (Table B.5). Structures in 100 ft water depth or less are almost always brought to shore for recycling, while above 100 ft, the frequency of donations increases rapidly. Thirteen

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[10] If one "outlier" point is removed from the set (a $2.5 million donation), then the average structure donation and donation per pile are $170,000 and $26,000, respectively.

[11] The average donation per towed structure is roughly $53,000 less than the average donation for structures not towed, and since the average tow distance was 20 miles, the inferred cost to transfer a platform to a reef site is estimated as (53,000)2/20 = $5,300/mile.

percent of all "eligible" CGOM structures have been reefed since the creation of LARP, with more than half of the structures in water depth greater than 200 ft reefed during this time.

The percentage of structures partially removed (*PR*) or toppled-in-place (*TIP*) as a function of water depth is computed similarly:

$$\mathrm{P}(TIP/PR) = \frac{\text{Number structures TIP/PR}}{\text{Number structures removed}}.$$

Platforms in deepwater are more likely to be reefed in place due to the higher operational costs and the additional savings that result from in-situ removals. This trend is expected to continue.

2.3. Model Development

2.3.1. Model Specification

The program donation for structure *s* is modeled through a linear functional,

$$DON(\mathrm{s}) = \alpha_i + \sum \alpha_i X_i ,$$

where the dependent variable is the donation, *DON*(s), reported in dollars, and the descriptor variables are described by X_1 = *WD* = water depth (feet), X_2 = *DIST* = distance to reef site (miles), X_3 = *NP*= total number of piles, and X_4 = *TIP* = topple-in-place or partial removal option. All the variables are numeric except the topple-in-place variable which is a binary indicator expressing if the structure was toppled-in-place or partially removed: *TIP* = 1, structure toppled-in-place or partially removed; *TIP* = 0, otherwise. Note that if *DIST* = 0, then *TIP* = 1, and if *DIST* > 0, then *TIP* = 0.

The coefficients of the functional, α_i, i = 0, 1, …, 4, are estimated through least-square regression. The coefficient α_0 represents a fixed term component, while α_i, i = 1, …, 4, are associated with the corresponding model variables. Decommissioning cost generally increases with water depth and structure complexity, and so the coefficients of the variables *WD* and *NP* (α_1 and α_3) are expected to be positive since the donation is expected to increase with these variables. As the distance towed to a reef site increases, one would suspect that potential savings resulting from rig donation would decrease, and we hypothesize that the coefficient of the *DIST* variable should be negative. Structures toppled-in-place or partially removed are expected to save more in decommissioning cost than a towed structure, and so the α_4 coefficient should also be positive.

2.3.2. Model Results

The regression model results are depicted in Tables B.6-B.8. In Table B.6, reef donations are disaggregated according to removal method. In Table B.7, structure disposition is decomposed in terms of structure complexity, and in Table B.8, models that normalize donation by the number of piles per structure are constructed.

In Table B.6, the regression model results provide a reasonably good indicator of the expected donation, especially for structures towed to location. Most of the model coefficients are statistically significant and of the proper sign. In Table B.7, reefed structures are disaggregated as a function of complexity. The range of the model fits are large but are considered reasonable for the factor set employed. In Table B.8, models that construct donation amount normalized by the number of piles are constructed. All the coefficients of the models are of the expected sign.

All cost estimates describe the outcome of an engineering estimate performed prior to the operation, which may subsequently be modified through negotiation. Cost savings do not represent the actual cost of the operation, and thus, are expected to exhibit weaker correlations with process descriptors than what otherwise would be expected. Water depth is the most significant variable across each of the models and donation is a negative function of tow distance, as expected. Additional variables might assist in deriving improved models, but the incremental improvement is likely to be marginal due to the nature of the processes involved and the limited ability of any factor set to capture the variability of the operation.

2.3.3. Example

Consider an 8-pile structure (NP = 8) located in 110 ft water depth (WD = 110) that is a candidate for reefing. The nearest reef planning area is located 15 miles away (TOW = 15). Predict the donation if the structure was reefed.

From Table B.6, for a structure towed to location,

$$DON(s) = -102{,}238 + 740(110) - 282(15) + 11{,}831(8) = \$69{,}580 .$$

From Table B.7, the model results yield,

$$DON(s) = 37{,}069 + 222(110) - 323(15) = \$56{,}534 ,$$

and from Table B.8 we obtain,

$$\frac{DON(s)}{NP(s)} = -10{,}485 + 156(120) - 47(24) = \$5{,}970/\text{pile},$$

or since the structure is an 8-pile, 8(\$5,970) = \$47,760. The difference in the donation estimates using the various models is due in part to the model uncertainty, the data employed to construct the models, and the preference of the user in model selection. It is difficult to know which of the three models is the "best" predictor of cost savings, and the user may apply the model with the optimum fit or choose another criteria to select a model. A range of values that bound the donation amount is probably the best approach to follow.

3. TEXAS ARTIFICIAL REEF PROGRAM

The National Fishing Enhancement Act (NFEA) of 1984 was designed to promote and facilitate efforts to establish artificial reefs for the purpose of enhancing fishery resources and commercial and recreational opportunities. In 1991, the Texas Artificial Reef Program was established based on the guidelines of the NFEA. Currently, 35 permitted reef sites from over 70 decommissioned platforms have been created offshore Texas.

The purpose of this chapter is to review the regulatory background and program statistics of the Texas Artificial Reef Program (TARP) and to construct quantitative models that describe the program donation. The history and organizational structure of TARP is first outlined.

3.1. Background

3.1.1. History

Resource managers have been involved in artificial reef development offshore Texas for over 50 years, and by 1984, over 2,000 de facto artificial reef areas had been created, including open water spoil disposal areas, piers and docks, jetties, liberty ships, and oil and gas well shell pads (Crowe and McEachron, 1986). Other than the liberty ships, however, most of these materials had little long-term success because they were easily broken up and moved by storms (Shively et al., 2003). Responding to the NFEA, in 1989 the Texas legislature directed the Texas Parks and Wildlife Department to develop the artificial reef potential offshore Texas, and in 1991, the Texas Artificial Reef Plan instituted the program (Stephan et al., 1996).

3.1.2. Liability

BOEMRE regulations release a platform operator from removal obligations in the federal lease instrument if a state agency responsible for managing fisheries resources accepts liability for the structure. The TARP established the state of Texas as the permittee for artificial reefs developed under the programs jurisdiction and appointed the Texas Parks and Wildlife Department as agent for the state. The state assumes ownership of the structure after being donated to the reef program and is responsible for the cost of buoy construction and replacement, operation, and liability in perpetuity. The donor and other participants constructing a reef under NFEA are absolved from liability provided the terms and conditions of the reef permits are met.

3.1.3. Donation Requirements

If the expected cost to remove a structure to shore exceeds the expected cost of reefing, then presumably reefing would be considered a viable alternative for the operator if the associated risks of the operations are comparable. Companies that donate structures to TARP are required to donate half of the expected cost savings from reefing into a trust fund to be used for research, administration, buoy maintenance, and other related activities. Third-party estimates of the cost for the removal alternatives are required *before* the operation is performed and from these estimated costs the donation amount is determined. Observe that since the estimated costs of the donation are determined prior to the actual operation, there is no way for the operator to adjust the values if unforeseen circumstances occur. Although decommissioning operations are usually performed on a turnkey (lump sum) basis, the contractor may be required to perform "extra work"[12] not covered in the scope of work and not included in the base bid.

3.1.4. Planning Areas

Several permit options are available under TARP (Shively et al., 2003). The Galveston District COE developed a policy that allows 40-acre reef sites to be permitted as long as site location and material placement meet the guidelines of the plan. Each 40-acre permitted reef site encompasses 1/16 of a square mile (1,320 ft x 1,320 ft) and has enough space to cluster at least nine jacket structures. The initial donor at a permitted site is allowed to topple the structure in place if clearance restrictions can be met. Owners of nearby structures are encouraged to participate in the program by transporting their structures to the existing site to avoid additional permitting. Current BOEMRE policy only allows siting of new reef sites in the High Island General Permit Area. Existing sites are still open to accept reefs.

Although many of Texas artificial reef sites are individually permitted, reefs created in the High Island leasing area are an exception (Figure C.1). Under the authority of a General Permit from the COE, artificial reefs created in the General Permit Area are constructed without the requirement of a 30-day public comment period. The permit requires the reef location to be at least 3 miles from another reef site, 2 nautical miles from any safety fairway and 1,000 ft from any active pipeline. In addition, the location must have at least 85 ft of water depth over the highest portion of the structure and must be at least one-half nautical mile away from any natural hard bottom communities (such as the Flower Garden National Marine Sanctuary East and West Banks). Reefs that do not meet these criteria require an individual permit from the COE issued after a 30-day public comment period.

3.2. Descriptive Statistics

3.2.1. Structure Donation

The number of oil and gas structures donated to TARP and donation amounts by year are shown in Table C.1. From 1990-2003, 73 structures were donated to the program – 9 3-pile jackets, 39 4-pile jackets, 25 8-pile jackets, one deck, and one caisson. A number of other objects have also been donated to TARP, including clay/shell culverts, tankers, fly ash blocks, concrete anchors, reef balls, quarry rocks, barges, buoys, net guard pieces, tugboats, and pipe structures (Shively et al., 2003), but such donations generally provide no "savings" to the owner or financial support to the program. As of May 2004, the Texas Artificial Reef Trust Fund has accrued approximately $9.6 million.

[12] If extra work is required that alters the critical path crane vessel time, the operator is charged at specified extra work rates. If extra work is required that does not alter the critical path crane vessel time, the operator is normally charged an hourly composite rate for all personnel and material required to correct the problem.

3.2.2. Removal Methods

From 1990-2003, 32 structures were towed (TOW) to a reef site, 16 were toppled-in-place (TIP) and 25 were partially removed (PR). In Table C.2, the average donation per structure (*DON/NS*), per donation (*DON*), and per pile (*DON/NP*) are shown according to removal method and structure type. The average donation varies with the structure type and removal method. For 4-pile structures towed to site, the average donation is $17,382 per structure versus $143,107 for structures toppled-in-place and $174,178 for structures partially removed. On a per pile basis, the same general relations are maintained, with towed structures providing a donation of $4,346/pile, and topple-in-place and partial removal methods yielding $35,776/pile and $42,225/pile, respectively. However, fourteen of the 20 4-pile structures provided no donation, and thus, may not be "representative" cost saving for the category. As the number of piles increases, the donation per structure generally increases, while the donation per pile decreases. The donation per 8-pile structure ranges between $143,181 (TOW) and $244,875 (PR).

3.2.3. Severance Method

For structures towed to site or toppled-in-place, the conductors and piles need to be severed and removed from the seafloor. Explosives are the preferred means of severance and occur in roughly 80 percent of the operations; e.g., for 4-pile structures, 9-of-11 structures toppled-in-place and 16-of-20 towed structures, used explosives. Mechanical methods of severance were employed in all partial removals (Table C.2).

3.2.4. Operator Involvement

Cal Dive/Blue Dolphin Energy and El Paso have donated the most platforms to TARP, and in total, nearly 40 operators have made at least one donation to the program (Table C.3). El Paso and CNG have contributed over 25 percent of the total program donation, with 60 percent of the program donations contributed by 27 operators.

3.2.5. Capture Probability Statistics

The total number of structures removed in the WGOM from 1990-2002 is shown in Table C.4 according to function type and water depth category. Removal statistics usually take a year or two after decommissioning is completed to be reported and included in the government database, and so the time frame of the analysis runs through the year 2002. Caissons are not considered appropriate reef material and are not included in the capture statistics. The probability a structure is reefed as a function of water depth is given by

$$P(\text{Reef}) = \frac{\text{Number structures reefed}}{\text{Number structures removed}}.$$

Structures in 100 ft water depth or less have about a 10 percent chance of being captured in the reef program, and in practice, structures in water depth less than 60 ft or so are almost always returned to shore. Capture probability increases rapidly above 100 ft, with 65 percent of all removed structures in 101-200 ft, and 82 percent of all structures in 201-400 ft, reefed. In total, 42 percent of all eligible WGOM structures have been reefed since TARP's inception.

3.3. Model Development

3.3.1. Model Specification

For structures donated to TARP, the donation amount is described through a linear model,

$$DON(s) = \alpha_0 + \sum \alpha_i X_i,$$

where the dependent variable is the donation reported in dollars, *DON*(*s*), and the descriptor variables are specified by X_1 = *WD* = water depth (feet), X_2 = *DIST* = distance to reef site (miles), X_3 = *NP*= total number of piles (integer-valued), and X_4 = *NS* = number of structures (integer-valued). Binary variables include structure type *ST*: *ST* = 0, 3-pile or 4-pile structures, *ST* = 1, otherwise; topple-in-place removal *TIP*: *TIP* = 1, topple-in-place or partial removal, *TIP* = 0, otherwise; and mechanical removal *METH*: *METH* = 1, mechanical cutting employed, *METH* = 0, otherwise. Note that if *DIST* = 0, then *TIP*= 1, and if *DIST* > 0, then *TIP* = 0. Since the *TIP* variable includes both topple-in-place and partial removal methods, *TIP* is not perfectly correlated[13] with *METH*.

3.3.2. Expected Signs

Decommissioning cost generally increases with water depth and structure complexity, and so the coefficients of the model variables *WD*, *NP*, *NS*, and *ST* determined from regression are expected to be positive. As the tow distance increases, one would suspect that the potential savings resulting from rig donation would decrease, and thus we hypothesize that the coefficient of the *DIST* variable should be negative. Structures toppled-in-place or partially removed are expected to save more in decommissioning than a towed structure, and thus, provide a larger donation, and so the *TIP* coefficient is expected to be positive. Inclusion of the mechanical cutting variable depends upon the decomposition strategy employed.

3.3.3. Model Results

The regression model results are depicted in Tables C.5-C.7. In Table C.5, reef donations are disaggregated according to removal method, and in Table C.6, models normalized by the total number of piles are constructed. In Table C.7, generalized models that incorporate all the descriptor variables are constructed.

Water depth is the most significant variable in all the regression models, and although donation is a negative function of tow distance, the tow distance variable is generally not statistically significant. The number of piles is a significant descriptor and of the expected sign, but the

[13] If *TIP* was defined to only include the partial removal method, then *TIP* would be perfectly correlated with *METH*, since only mechanical methods or diver cuts are used in partial removals.

coefficient of the number of structures is ambiguous. We would expect that the donation amount would increase with the number of structures donated, but scale economies may also occur which would dampen the effect. The donation per pile model is considered inferior to models where the number of piles is an explicit variable.

All cost estimates describe the outcome of an engineering estimate performed prior to the operation. The actual costs of the operation do not effect the donation. Cost savings do not represent the actual cost of the operation, and thus, are expected to exhibit weaker correlations with process descriptors than what otherwise would be expected in a traditional cost function. Water depth is the most significant variable across each of the models considered and donation is a negative function of tow distance, as expected.

3.3.4. Example

A typical application of the regression models is illustrated for a structure towed to location. Consider an 8-pile structure (NS = 1, NP = 8) located in 130 ft water depth (WD = 130) that needs to be towed 15 miles (TOW = 15) to the reef planning area. If the structure is reefed, the donation amount can be estimated as follows.

From Table C.5, the donation function is written,

$$DON(s) = -156{,}543 + 893WD - 193DIST + 14{,}852NP + 2{,}157NS\ ,$$

and after inserting the structure data, yields

$$DON(s) = -156{,}543 + 893(110) - 193(15) + 14{,}852(8) + 2{,}157(1) = \$59{,}765\ .$$

From Table C.6 we obtain,

$$\frac{DON(s)}{NP(s)} = -23{,}090 + 218(130) - 83(15) + 275(1) = \$4{,}280\text{/pile},$$

or since the structure is an 8-pile, 8($4,280) = $34,240. From Table C.7, the generalized donation model yields $DON(s) = \$53{,}523$.

4. IMPACT OF THE 2005 HURRICANE SEASON ON THE LOUISIANA ARTIFICIAL REEF PROGRAM

There is extensive experience with decommissioning offshore structures and rigs-to-reef programs in the GOM, but significantly less experience for hurricane destroyed structures. The decision to repair, replace or abandon damaged and destroyed infrastructure, the manner in which decommissioning activities are performed, and the options available to operators are more complex and constrained compared to normal operations. The Louisiana Special Artificial Reef Site (SARS) program was created to accommodate structures destroyed in hurricanes and other exceptional circumstances to provide operators additional options for decommissioning.

The purpose of this chapter is to review the status of the SARS program. We begin with a quick overview of the 2004-2005 hurricane season and review the risk associated with decommissioning hurricane destroyed infrastructure and the removal options available to operators. This is followed by a description of the criteria and procedures used to establish a SARS. The screening criteria employed in project evaluation and SARS approval concludes the chapter.

4.1. 2005 Hurricane Season

The 2005 hurricane season in the GOM was the most destructive and costliest natural disaster in the history of the United States, and was especially damaging to the offshore oil and gas industry. Five hurricanes passed through the GOM in 2005, but only Hurricane Katrina, a category 5 storm, and Hurricane Rita, a category 4 storm, caused damage (Figure D.1). Hurricane Katrina destroyed 44 platforms and severely damaged 20 others, while Hurricane Rita destroyed 69 platforms and damaged 32 others (Table D.1, Figure D.2). Eight drilling rigs were also destroyed and 19 rigs sustained significant damage. Katrina and Rita were responsible for a record $15 billion loss to the energy markets, two-thirds of which have been attributed to physical damage (Willis Energy Market Review, 2006).

Offshore platforms are vulnerable to the extreme wind speed and wave height caused by hurricanes. Failure of primary structural components such as braces, jacket legs, deck legs, and piles often lead to listing or toppled units. Loadings caused by wave inundation of the deck are usually the primary cause of damage, since deck inundation increases the horizontal load and overturning moment, resulting in the failure of structural members and collapse (Figures D.3 and D.4). Bottom current loading or foundation failure may also lead to failure because of soil instability and mudslide conditions. Mooring on mobile offshore drilling units may fail, setting units adrift as they drag their anchors, before listing, capsizing, or grounding ashore.

A structure destroyed by a hurricane requires a costly and time-consuming clean-up operation. There is extensive experience with decommissioning offshore structures in the GOM, but significantly less experience for structures destroyed by natural forces. Only a small fraction of the total number of removed structures, less than 3 percent or so, has been destroyed by extreme weather. Because hurricane events are random in nature, the geospatial distribution of destroyed structures is usually higher in high density regions, which are often distant to reef placement sites.

The SARS category was created to accommodate reef materials that fall outside the planning areas of the LARP, but because of the manner in which the structures are laid down, special oversight is required to ensure that program criteria are met and that potential negative user impacts are minimized. Will the structure benefit recreational or commercial fishing, or fish habitat, at its current location, or should the structure be removed completely or transferred to another site? Will the site pose a threat to navigation or other users, or interfere with future oil and gas field development? Could the site serve as a biological field study or a location for future decommissioned structures?

Regulators evaluate the technical and environmental aspects of each SARS project along with the trade-offs involved with establishing new reef sites outside the designated areas of the LARP. If the candidate structure satisfies criteria that enhances marine habitat, then it would be considered for possible inclusion as a SARS; otherwise, if it is determined that the structure does not benefit the marine habitat or poses a significant risk to other user groups, then it would be rejected as a SARS candidate and be removed in accord with federal requirements.

4.2. Decommissioning Hurricane-Destroyed Infrastructure

Under normal conditions, decommissioning operations are considered a safe and environmentally benign activity. Well-defined prescriptive regulatory policies safeguard human health and the environment, and because contractors have extensive experience in decommissioning, operational risk are well known and manageable (Schroeder and Love, 2004). From an international perspective, many of the issues that arise in the GOM take on specific regional characteristics; e.g., (Osmundsen and Tveteras, 2003; Hamzah, 2003; Parente et al., 2006). In the GOM, the nature of the operation and short duration of the activity means that personnel are generally exposed to minimal safety risks.

A structure damaged or destroyed in a hurricane complicates the decision-making process; it affects the decision[14] to repair, replace or abandon the structure; the manner in which decommissioning activities are performed; and the options available to operators. Since hurricane destroyed structures are frequently toppled in place in neither a planned nor controlled manner, complications often arise in topsides removal and the wellbore plug and abandonment process. Removal options for destroyed structures are similar to normal decommissioning activity but are constrained by safety considerations, technology, available equipment, and cost.

The risks involved in decommissioning hurricane-destroyed infrastructure are significantly higher than under normal conditions. A platform destroyed in a hurricane lies horizontally on the seafloor, often in a tangled web of steel (Figures D.5 and D.6), and in some cases, a significant portion of the structure may be submerged under mud. Preparation and inspection activities associated with normal decommissioning are forgone, and since the structure lies on the seafloor, well access is significantly more difficult and often requires the development of special equipment and tools to perform plugging operations.

[14] Several factors impact the decision to repair, replace, or abandon damaged and destroyed infrastructure. The return on investment from fabricating/installing a new platform, subsea assembly or pipeline interconnection depends upon the cost of removing/repairing the destroyed/damaged structure, the cost to re-enter/redrill wells, expected remaining reserves, current and expected future prices, operating cost and strategic considerations.

Debris will need to be cut and moved by diving personnel or remotely operated vehicles to establish access to wells, and diver exposure time will greatly exceed the time normally required in operations, impacting the risk of the activity and significantly increasing cost. To remove topsides equipment, deck, and substructure may also require the development of special service vessels.[15] Complete removal may not be technically feasible or may pose risks to diver personnel that exceed those of acceptable conditions. The cost to decommission a destroyed structure may range anywhere from 5-25 times the cost of a normal operation.

4.2.1. Well Plugging and Abandonment

The purpose of well plugging and abandonment (P&A) is to provide downhole isolation of hydrocarbon zones, protect freshwater aquifers, and prevent migration of formation fluids within the wellbore or the seafloor. Wells are shut-in prior to the arrival of extreme weather, and depending on the extent of damage, will either be temporarily or permanently abandoned. All wells on a lease must be permanently abandoned within 1 year after the lease terminates or if the BOEMRE 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. Economic and strategic considerations determine if the wells of a destroyed structure should be temporarily or permanently plugged.

Shut-In Status

A shut-in well is a flowing well that has its Christmas tree, master valves, wing valves, and subsea safety valve closed. Subsea safety valves serve to protect the environment from leakage should the topsides equipment be damaged or destroyed, and in the event that a structure is toppled, the subsea safety valve is the last line of defense preventing an oil/gas blowout. A well can be maintained in a shut-in state for any length of time as long as periodic maintenance procedures are followed.

Temporary Abandonment Status

In a temporary abandonment, 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 (Kaiser and Dodson, 2007). A temporary abandonment is more secure than a shut-in well but is also more expensive to perform. Shut-in and temporarily abandoned wells are considered a temporary, or transitory, state in the life cycle of a well.

Permanent Abandonment Status

A permanent abandonment is the terminal state of a wellbore. In a permanent abandonment, former producing horizons are plugged and casing is cut off below the mudline according to

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[15] A $30 million derrick barge called "The Bottom Feeder" was specially designed for hurricane clean-up operations and deployed out of Corpus Christi, Texas, on June 12, 2007 (Bahr, 2007). The Bottom Feeder consists of twin barges connected by steel truss frames that act as stabilizers as a targeted object is reeled up from the ocean floor. Four 200-ton winches attached to the trusses deploy hooks to retrieve sunken topsides and jacket components. The market dayrate for vessel utilization was $150,000 in September 2007.

regulatory guidelines. Prior to operations, debris will need to be cleared around the site to establish access to the wellheads, and because of the loss of the structure, well access will be more complicated and expensive. P&A operations on destroyed structures take on many of the characteristics and cost of plugging a wet (subsea) well.

4.2.2. Structure Removal

Infrastructure destroyed by accident, terrorism, or natural catastrophe are decommissioned according to the same federal regulations that guide normal decommissioning operations, but depending upon the nature of the destruction and the market conditions in the months following the event, special conditions and delays may occur. Under normal conditions, the operator has three options for structure removal: complete removal, partial removal and toppling-in-place. These removal options for destroyed structures are similar to normal operations but are constrained by safety considerations, technology, available equipment, and cost.

4.2.3. Site Clearance and Verification

Site clearance and verification is the last task to occur in decommissioning. Under normal conditions, 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 ensures that the site is clear. Site clearance and verification requirements for reefed structures are frequently waived; for structures destroyed in a hurricane, steel and other material debris may remain on the seabed, in and around the site, if approved by the regulatory agency.

4.3. LARP Statistics

The number of structures donated to LARP, donation amounts, and average annual donation per structure are shown in Table D.2. Eight of the 147 platforms donated to LARP through 2006 were destroyed by hurricanes, and 29 of the 147 structures exist as SARS.

4.4. SARS Program

4.4.1. Definition

It was clear from the inception of the Louisiana Artificial Reef program that special accommodations would be required to capture “materials of opportunity” that arise from unusual and unforeseen circumstances. The Special Artificial Reef Site (SARS) program was created in 1991 when a drilling rig collapsed in South Timbalier 86 during Hurricane Juan. A SARS is an artificial reef site created and maintained by the Louisiana Department of Wildlife and Fisheries to take advantage of materials of opportunity located outside designated planning areas. A site, and materials contained at the site, qualify as a SARS when one or more of the following criteria are met: (1) There is a historical or biological significance associated with the site, such as a successful fishing spot frequented by fishermen and/or divers; (2) The site is part of a cooperative effort between the LARP and other state, federal or private groups; (3) The site contains shipwrecks or other derelicts which cannot be practicably removed or relocated; or (4)

The site forms an integral part of experimental or demonstration projects undertaken by the LARP.

4.4.2. Selection Criteria

Several criteria must be satisfied to be considered as a potential SARS location (Amendment II to LARP, 2003): (1) The site must provide benefit to recreational and/or commercial fishing, or fish habitat; (2) Removal of existing material from the site would have a negative impact on fish populations; (3) Designation as SARS would not pose a threat to navigation; (4) The area does not occupy currently trawlable bottom; (5) Inclusion of the SARS would have an overall positive impact on user groups; and (6) Except for possible trace amounts, the structure should be free and clear of any hydrocarbons or other hazardous materials.

4.4.3. Procedures

Procedures to review, and approve or reject, SARS applications were adopted in 1991 and revised and modified in 2003 (Amendment II to LARP, 2003). The program framework is meant to be transparent and provide equal non-discriminatory review to all applicants, as discussed in (Kaiser and Kasprzak, 2007). Formally,

1) The Louisiana Artificial Reef coordinators will draft a proposal to establish a SARS for submission to the Artificial Reef Council. The proposal shall include location, clearance, bottom profile, condition of structure and list of potential hazardous material, and justification that the criteria outlined above are met.
2) Following acceptance of the proposal by the Louisiana Artificial Reef Council, the intent to create a SARS will be announced through a Louisiana Department of Wildlife and Fisheries News Release.
3) Thirty days following news releases, if no major objections are received, the Louisiana Artificial Reef Coordinator will apply for the necessary permits. In the event objections are received, a public hearing will be held to provide further information before a final determination by the Council.
4) If appropriate, a Deed of Donation will be agreed upon by the donor and recipients of the reef material.
5) The Secretary of the Department of Wildlife and Fisheries will sign all necessary permits and the Deed of Donation.

4.5. SARS Program Statistics

4.5.1. SARS Approvals 1991-2005

Before the 2005 hurricane season, 29 structures destroyed in hurricanes, construction accidents, biological studies, and deepwater reef criteria were approved as SARS locations. These structures included two drilling barges and one drilling rig (Table D.3). Most SARS blocks have the capacity to accommodate between 7-10 platforms as shown in the development of SARS blocks WD-134, MP-243, and EI-313. At SARS blocks EI-273, EI-309, EI-322, EI-324, EI-384, SP-89, and VE-395, only one or two structures are currently contained per site, but the locations are likely to attract additional structures as future decommissioning activity occurs in the region.

4.5.2. Post-Katrina SARS Approvals

Following Hurricanes Katrina and Rita, the LARP Advisory Council held meetings to review the scope of the offshore damage and to discuss the expected impact on the program. Projects were screened with a Reef Priority Index (*RPI*) to prioritize projects received for consideration, and then evaluated on a case-by-case basis, taking into account factors such as the habitat value of the project, fishing reports available at the site, ability of the site to serve as the location for additional structures, distance to nearby planning areas and other SARS sites, clearance, relief, pipeline issues, and proximity to mud slide prone regions. The Advisory Council made recommendations to approve, to approve with modification, to discuss for future planning purposes, and to reject. Rejected projects cannot be resubmitted for future evaluation.

Locations with no active pipelines transversing the lease were preferred SARS candidates, and active pipelines within or bordering a lease were reviewed when the distance was less than 1,000 feet. Mud slide prone areas are generally not appropriate for reef sites, since platforms may move, break, and/or become submerged over time, and submerged/buried platforms provide little or no habitat value. Project modifications typically require platform additions or removals at a proposed site, and discussion for planning purposes is normally centered around the suitability of the site for future additions.

In June 2006, 25 projects representing 39 destroyed platforms were submitted for SARS consideration. In total, 7 projects representing 21 platforms were approved (Table D.4, Figure D.7).

In November 2006, 13 projects representing 25 platforms and 3 Mobile Offshore Drilling Units (MODUs) were reviewed for SARS consideration, including new and previously reviewed/reconfigured projects. Three projects representing 14 platforms were approved (Table D.4 and Figure D.7). None of the MODU projects were recommended for approval. The level of project submissions are believed to have peaked, and it is anticipated that SARS submissions from the 2005 hurricane season will clear by the end of 2007.

At the end of 2006, 10 projects representing 35 platforms have been approved as new SARS locations, effectively doubling the number of SARS locations within LARP. The Council has stated its desire to accommodate structures that provide suitable habitat value while minimizing the total number of sites. This has generally required operators to group/bundle multiple destroyed platforms at one site to gain Council approval. For each SARS that is added to LARP, it is required that an equivalent area be removed from one of the nine designated areas, but because the number and size of SARS regions are so small relative to the total LARP area, the impact on the physical makeup of LARP regions is minor. As SARS locations are added to LARP, the LARP begins to take the regulatory characteristics of the Texas Artificial Reef Program, where operators are provided more flexibility in permitting partial removals and toppling-in-place (Shively et al., 2003).

4.5.3. RPI Screening Criteria

The majority of the destroyed infrastructure from the 2005 hurricane season was located in the federal waters offshore Louisiana. State officials were inundated with requests from operators to establish individual SARS locations at a number of these sites. A RPI was created to screen projects and to identify the most worthy candidates.

RPI is defined on a project basis as follows:

$$RPI = HV(A+B+C),$$

where the habitat value (HV) represents the number of platforms involved in the project, and A, B, and C are weight factors based on the distance of the project to the nearest reef site ($REEF$), distance to shore ($SHORE$), and clearance at the site ($CLEAR$). HV enters RPI multiplicatively, so there is a preference for two or more platforms to comprise a SARS. The value of the weighing factors are as follows:

$$A = \begin{cases} 1, & REEF \le 2 \\ 2, & 2 < REEF \le 10 \\ 3, & REEF > 10 \end{cases} \quad B = \begin{cases} 3, & SHORE \le 35 \\ 2, & 35 < SHORE \le 70 \\ 1, & SHORE > 70 \end{cases} \quad C = \begin{cases} 2, & 50 < CLEAR \le 85 \\ 3, & 85 < CLEAR \le 130 \\ 1, & CLEAR > 130 \end{cases}.$$

The distance to the nearest reef site ($REEF$) and shore ($SHORE$) is measured in miles; clearance ($CLEAR$) is measured from the top of the submerged structure to the water line in feet.

The weight factors serve to distinguish traits important in project definition. As the distance to the nearest reef site increases, it is more likely that towing the structure to the site would not be economic. The value of A gives greater weight to projects that are farther away from a designated reef site. The value of B is related to the distance to shore. A site within 35 miles to shore is given priority since such a site would be the most likely to attract recreational fisherman, while as the shore distance exceeds 70 miles, the weight factor drops to unity. The amount of relief at a site is an important factor in habitat value. The best habitat conditions for reefs maintain the greatest amount of relief within the clearance requirements specified by the Coast Guard. The value of C reflects the preference for structures that have 85-130 feet clearance.

The RPI values for approved SARS projects are shown in Table D.4 and average 26.2 per project. Average RPI values for the 27 rejected SARS projects was 6.5 per project.

4.5.4. Notable Applications

Three SARS projects are of particular interest. One of the first SARS approved was for the Typhoon tension leg platform, a deepwater floating structure in GC-237 which broke free of its tensioned legs and floated nearly 100 km from its original location before capsizing. In June 2006, Typhoon was accepted as a SARS in the Eugene Island 270 area.

An 8-pile platform owned by Taylor Energy and servicing 28 producing wells in MC-20 failed in a mud-slide region. The platform was pushed nearly 400 feet from its original location, and upon inspection, was found to be submerged nearly 75 percent below the mudline. The volume of mud that will have to be dredged to access/lift the structure has been estimated to be equivalent to the volume of the New Orleans Superdome, and the project is expected to cost at least $500 million (Taylor, 2007a; Taylor, 2007b). As of June 2009, well plugging work is still on-going. The BOEMRE has called the project the most extensive well abandonment challenge in the Gulf of Mexico and is expected to require the construction of a coefferdam to allow workers to access the structure. The Taylor platform was submitted to SARS but was not approved because of the lack of habitat value. Being largely submerged below the mudline, there is little hard surface which could become useable reef.

BP proposed a reef site for an 8-pile platform destroyed at GI-40/48, less than 3 miles from the Louisiana Offshore Operating Port (LOOP) anchorage area. Clearance restrictions will require lighted buoys at the site, and because of the proximity to LOOP, no final decision has yet to be made. Evaluation and risk assessment studies are on-going.

4.6. BOEMRE Policy on Toppled Facilities

After the 2005 hurricane season and the unprecedented number of SARS applications BOEMRE received to reef toppled structures, BOEMRE enhanced its review criteria for approving rigs to reefs proposals.

4.6.1. Engineering, Stability, and Environmental Reviewing Standards

The BOEMRE GOMR will review each decommissioning application proposing Rigs-to-Reef to ensure that problematic engineering and/or environmental uncertainties are eliminated and the BOEMRE Rigs-to-Reefs Policy does not give the impression of a disposal program. The following set of standards will apply:

1) Reef material must be stable and not endanger nearby infrastructure and/or protected resources:
    - No debris piles, debris fields, or reef baskets will be allowed under OCSLA regulatory permitting;
    - Reef sites will not be permitted in areas of seafloor instability or known mudslide activity;
    - Reef material must be established in the most stable orientation in its final disposition;
2) Reef sites must be free from all potentially hazardous/nonstructural material:
    - Standing Decks – all nonstructural components must be removed (i.e., equipment, vessels, piping/tubing, wiring, etc.) and a facility inspection must be conducted/documented by BOEMRE or a third-party prior to reefing;
    - Submerged Decks – all decks and their separated components/equipment must be removed;

3) Reef sites must not hinder future OCSLA oil and gas, marine mineral, and/or renewable energy/alternative activity operations:
    - Future reef sites will not be allowed within 5 miles of established/pending reef locations to minimize the impact to future pipeline operations;
    - Future reef sites will be reviewed for impact to future resource extraction (e.g., oil, gas, sulphur, and sand resources);
4) Reef sites must not lead to avoidable space-use conflicts with other users of the GOM OCS:
    - Some proposals may require public review/commenting periods under NEPA (primarily a concern for abandonment-in-place); and
    - Reef sites that fall within the administrative/Coastal Zone Management Act boundary of another state could require coordination/consistency review by both applicable agencies.

4.6.2. Reef-Approval Guidelines

Pending additional policy coordination between necessary State and Federal agencies and the opportunity for public participation, BOEMRE GOMR will only grant Rigs-to-Reef departures for platform-removal applications proposing the structure's siting within any:

1) New reef sites within the existing Texas General Reef Permit Area, Louisiana Artificial Reef Planning Areas, or Mississippi Artificial Reef Development Zone 4;
2) Existing/established artificial reef sites (i.e., previously reviewed and approved by BOEMRE GOMR) both within and outside of the areas previously mentioned; and
3) Platform-removal permit applications with Rigs-to-Reef proposals received prior to implementation will be exempt from the Reef-Approval Guidelines; however, they will be subject to the applicable Engineering, Stability, and Environmental Reviewing Standards noted above.

5. ASSESSMENT OF PLATFORM-BASED MARICULTURE IN THE GULF OF MEXICO

In this chapter, we discuss the prospects of an offshore mariculture industry in the GOM, specifically focusing on the alternative use of oil and gas infrastructure in the mariculture industry. We first describe a potential platform based OOA project and discuss the costs and benefits of using platforms in offshore mariculture including the ecological costs and benefits. We then review the offshore mariculture industry in the U.S. and discuss failed platform based projects. Next, we discuss site selection for offshore platform based mariculture in the GOM and end with conclusions.

5.1. Open Ocean Aquaculture

There has been a great deal of recent interest in open ocean aquaculture (OOA), the expansion of marine aquaculture to offshore areas (Marra, 2005; Skladany et al., 2007). Many commercial capture-based fisheries have already been depleted and their continued use is neither ecologically nor economically sustainable (Myers and Worm, 2003). Additionally, the culture of marine organisms, especially shrimp and salmon, in coastal areas has significant environmental impacts. As a result, the idea of raising marine organisms in large offshore cages for human consumption has become an attractive alternative to predatory fisheries and coastal aquaculture.

Eighty-one percent of the seafood consumed in the U.S. is imported (approximately 3 million tons worth 13.4 billion dollars; (Upton and Buck, 2008)). To reduce this trade deficit, the U.S. Department of Commerce plans to quintuple the production of farmed fish, crustaceans and mollusks from just under $1 billion to $5 billion by 2025 (Skladany et al., 2007). Most of this increased production will be from an increase in the number of high value species farmed and much of this will come from mariculture.

One of the largest obstacles to OOA is the isolation from onshore supply bases (Bridger, 2004; Stickney, 2004). OOA will require large amounts of food and energy to power automated systems as well as relatively large number of personnel to achieve economies of scale.

There are several methods for the logistics of offshore aquaculture (Table E.1). The first option is to base crews on land and to make daily trips to the site. This is likely to be the most cost effective method for near-shore sites, but is unlikely to be feasible for farther offshore locations (Ryan, 2004). Even for nearshore sites, some kind of remote feeding and monitoring equipment may be needed for operations without permanent offshore personnel. The second is to use some type of special-purpose vessel that would stay on-site for extended periods (Ryan, 2004). Bridger and Goudey (2004) envision a jack-up barge that would service a dozen individual cages. The third option is to use existing oil and gas platforms as a base of operations (Figure E.1). However, suitable sites near shore are limited due to user conflicts, ecological impacts and geography and it may become necessary for OOA operations to locate further from shore and thus adopt an alternative logistical strategy.

This co-development of offshore energy and mariculture resources has been studied since the early 1990’s (Caswell, 1991; Reggio, 1987) and several technical reports and feasibility studies have been conducted to investigate this possibility (Waldemar Nelson International, 2001; Louisiana Department of Natural Resources, 2005). Generally, these reports have concluded with positive analyses of the feasibility and prospects for the use of offshore infrastructure in the mariculture industry; however, there is yet to be a successful pairing of mariculture with the oil and gas infrastructure of the GOM, despite the fact that offshore aquaculture has developed elsewhere.

5.2. Regulatory Authority

The activity of platform-based mariculture in the Gulf of Mexico falls under the authority of the National Oceanic and Atmospheric Administration (NOAA). Under NOAA, the Gulf of Mexico Fishery Management Council developed the Aquaculture Fishery Management Plan (FMP) to establish a regionally-based regulatory framework for managing the development of an environmentally sound and economically sustainable offshore aquaculture industry in federal waters of the Gulf of Mexico.

The primary environmental protections proposed in the FMP would:

- Limit the species that may be cultured to Gulf Council-managed species (except shrimp and corals) that are native to the Gulf of Mexico.
- Prohibit the culture of non-native, genetically modified, and transgenic species; prohibit aquaculture operations from being sited in habitat areas of particular concern, marine reserves, marine protected areas, Special Management Zones, and permitted artificial reef areas identified as such through Gulf Council FMPs and implementing regulations, as well as coral reef areas.
- Create a restricted access zone for each permitted facility.
- Cap the total amount of fish that could be cultured annually, as well as the relative contribution of each individual operation to the annual cap.
- Establish a broodstock of organisms from the Gulf of Mexico to use in aquaculture facilities.
- Establish numerous recordkeeping, reporting and operational requirements designed to minimize or mitigate potential environmental impacts.

Other Federal agencies have regulatory authority for offshore aquaculture in the Gulf of Mexico as well. The Bureau of Ocean Energy Management, Regulation and Enforcement has regulatory authority over the right-of-use and easement of oil and gas platforms for aquaculture activities. The U.S. Army Corps of Engineers has regulatory authority over siting aquaculture facilities and the Environmental Protection Agency has regulatory authority with regards to water quality issues. NOAA has the regulatory authority to address marine resource conservation issues, which includes offshore aquaculture activities.

5.3. Platform Systems

There are a wide variety of methods for conducting marine aquaculture and a variety of potential aquaculture-related uses for oil and gas platforms. We focus on one potential use, the culture of finfish to maturity in large cages, serviced by an offshore platform. The system consists of a large fixed platform that is used as housing for staff, storage for feed and equipment, electricity generation and possible physical support for cages and a nearby shorebase which may also serve as a hatchery and nursery. Part of the platform might also be used as a nursery to allow fish to grow from their shipping weight to their stocking weight.

We imagine that there will be several cages around a single platform. The cages will most likely be submersible (Figure E.2) as this generally allows for stronger cages able to withstand the open ocean, but they could also be of a net pen design (Figure E.2).

Platforms could be acquired in one of several ways. A mariculture operator could purchase a platform from an oil and gas operator, a mariculture and oil company could co-use a facility simultaneously, or a mariculture company could rent the facility from an operator after its economically useful life has expired. Due to the potential for conflicts between the interests of the oil and mariculture operators, the simultaneous use of oil facilities seems the least likely.

5.4. Costs and Benefits of Using Offshore Oil and Gas Platforms

Open ocean aquaculture does not require manned platforms in order to function. There are several locations around the world in which offshore operations function without platforms (Ryan, 2004). However, most of the existing offshore mariculture operations might be considered exposed rather than truly offshore (Bridger, 2004). There are a number of advantages that a truly offshore aquaculture system may accrue through the use of a platform.

5.4.1. Advantages to Mariculturists

Open ocean aquaculture is likely to require economies of scale in order to be economically viable. A large farm will require several full time staff, an electrical power supply for automated equipment and large amounts of food. By using a platform, supply boats could resupply the platform once a week or less rather than every day as in unmanned farms (Jin, 2008). This would save significant amounts of money and would ensure that brief weather events would not disrupt operations. There has been no study of the tradeoff between the capital and transportation costs associated with using platforms. However, Jin (Jin, 2008) did find that reducing the number of trips to a site by increasing vessel payload (as would occur through the use of a platform) increased the present value of a hypothetical operation approximately 2 to 5 times depending on the distance from shore.

Platforms would also allow for 24 hour on-site security and monitoring. These farms would be located miles from shore and may be subject to vandalism by opponents of the industry, theft or predator attacks. Even if remote monitoring systems are used, response times for shore-based personnel would likely be too long to serve as an effective deterrent.

Depending on the cage configuration a platform might also serve as an anchor for nearby cages. It is not clear if all offshore oil and gas platforms could serve as appropriate anchors (Bridger and Goudey, 2004) but doing so might keep cages from drifting away during storms. However, anchoring cages to platforms could create strong lateral forces acting on the platforms during storms and could increase the risk of platform toppling.

The GOM has a well developed service vessel industry with several ports distributed across the Gulf coast including Venice LA, Fourchon LA, Intracoastal City LA, Cameron LA, Sabine TX, and Galveston TX. This ensures that regardless of the location of the platform, there will be shore-based infrastructure nearby.

5.4.2. Advantages to Oil and Gas Operators

Advantages might also accrue to oil and gas operators. Companies must remove all structures from a lease within one year after production ends on a lease. Oil and gas operators could benefit by delaying the decommissioning of platforms due to the time value of money (assuming that decommissioning costs scale with inflation and that firms have investment options that exceed the rate of inflation; decommissioning costs may increase faster than inflation or slower than inflation due to technological learning).

Oil and gas operators could also benefit by either charging fees for the use of their platforms or through the sale of platforms and the avoidance of decommissioning costs. It may be more advantageous and likely for operators to sell platforms then to rent them as this would decrease (but not eliminate) their liability exposure. Rents would have to be quite high in order to compensate for the increased liability (Fernandez, 2005).

5.4.3. Disadvantages to Mariculturists

A mariculture operator would have to acquire a surety bond that covered the cost of decommissioning the platform. Sureties are generally very conservative, and it would be likely that they would require a mariculture operation to collateralize the bond, requiring additional capital. The costs for a surety bond would range from 2 to 5 percent of the decommissioning costs per year to 100 percent collateralized bond in which the operator would have to provide the surety with the full value of the bond.

It is also important to note that in the oil and gas industry, platforms are not generally decommissioned one by one, but instead an operator may decommissions all of the platforms in an area simultaneously, saving money through scale. This would not be an option for open ocean aquaculture. However, it might allow mariculturists an opportunity to use platforms that were past their economically useful life but not yet ready for decommissioning.

The high capital costs associated with the purchase of oil and gas facilities could also be a disadvantage to using oil and gas facilities in offshore aquaculture. All open ocean aquaculture systems will require significant capital for cages, boats, onshore infrastructure and permitting expenses. The addition of the platform could add $1 million or more in capital costs. Studies have shown that open ocean mariculture projects are barely economically feasible without the additional expenses of platforms (Lisac and Muir, 2000; Kam et al., 2003; Posadas and Bridger, 2003; Ryan, 2004; Jin, 2008; Kirkley, 2008). It is not clear if the added capital expense would be worth decreased operating expenses associated with decreased fuel usage.

5.4.4. Disadvantages to Oil and Gas Operators

One of the most important problems for operators interested in pursuing the sale of platforms to third parties is liability (Dougall, 1994). The liability to decommission a platform may be a larger cost than the platform itself. Decommissioning costs vary with the size and water depth of a platform, but for a 4-piled structure in shallow water (0 to 60 m) costs average $1.5 to 2.5 million (Kaiser and Pulsipher, 2008). However, the liability, both for the mariculture operator and the original owner can be far greater. If a hurricane damages or destroys the structure, the costs of removal can increase dramatically.

The U.S. regulations stipulate that an offshore oil and gas operator can never be free of their obligations to decommission a site. Even if they pass ownership on to a mariculture operation, if that mariculture operator goes bankrupt and the funds are not available to decommission the site, the original operator would be liable. This is a significant disincentive for the original owner to sell or lease the site to an aquaculture operation.

Supplemental bonds are required in the GOM for leases that do not meet a minimum financial threshold. For mariculture operations, it is conceivable that the Federal Government will require financial assurance to ensure that structure removal and site clearance operations will be performed in the event the operator goes bankrupt. For oil and gas structures that are transformed into a mariculture site, the supplemental bond will be similar to existing requirements as described in Kaiser and Pulsipher (2008) except that P&A requirements will likely have already been performed.

5.4.5. Ecological Impacts

The positive and negative ecological impacts of OOA have been discussed in a number of places (Riedel and Bridger, 2004; Goldburg and Naylor, 2005; Naylor and Burke, 2005). OOA is presumed to have fewer adverse ecological impacts than coastal aquaculture; however, there are many important negative ecological impacts including genetic pollution, nutrient discharge, the artificial selection and transmission of parasites, and a global decline of available fish protein. These ecological effects are applicable to all OOA projects. There are both additional positive and negative ecological impacts associated specifically with platform-based mariculture.

By forestalling the removal of an offshore oil and gas platform, the habitat diversity associated with the platforms is maintained, leading to increased biodiversity. It has been estimated that 10,000 to 30,000 fish live on each platform in the GOM (Stanley and Wilson, 2000) and the platforms in the GOM often provide the only locally available hard surfaces increasing local habitat diversity and biodiversity. Additionally, platform removal through explosives and site clearance through trawling can have localized impacts on nearby cetaceans and the benthic community, respectively; delaying platform removal will delay these impacts.

However, it is also important to recognize that the use of oil and gas structures for mariculture could have significant impacts on the platform ecosystem. Platforms harbor diverse ecosystems and provide habitat for threatened and endangered species (Kolian and Sammarco, 2005). While the nutrient impacts of OOA are expected to be minimal compared to coastal aquaculture, they could still be locally important and could serve as a nutrient source for the associated platform.

Adverse ecological impacts of drill cuttings from oil and gas platforms are well known (Grant and Briggs, 2002). Many platforms have large piles of cuttings lying beneath them; these cuttings can include mercury, a neurotoxin and carcinogen (Trefry et al., 2007). Additionally, large volumes of water are co-produced with oil and gas from offshore platforms. This produced water is separated from the oil and gas and either reinjected into a deep formation or discharged to the ocean (USDOI, MMS, 2006). Typically, produced water will contain hydrocarbons, corrosion inhibitors, biocides, demulsifiers, and radioactive materials. It is thought that produced water reaches non-toxic levels within 100 m of its release point due to dilution (USDOI, MMS, 2006). However, finfish and shellfish species are known to have bioaccumulative characteristics (Shakhawat et al., 2006) and these molecules could bioaccumulate in fish causing adverse health effects in people consuming them (Lewis and Chancy, 2007).

While devastating oil spills are rare in the GOM, BOEMRE predicts that over the five year period between 2007 and 2012, nine large oil spills (1,000 bbl or more), 50 small oil spills (50 to 999 bbl) and 550 very small oil spills (under 50 bbl) will occur (USDOI, MMS, 2006). If any of these spills occurred near a mariculture project it could cause a catastrophic failure.

A great deal of industrial activity occurs in the GOM on a daily basis. This industrial activity may, in some cases, cause noises that could stress fish. Sources of noises could come from nearby marine traffic, seismic exploration, explosive severance operations, drilling or construction, especially pile-driving. The effects of marine noise are not as well studied in fish as they have been in marine mammals, but studies have shown that the ears of pink snapper are badly damaged when exposed to nearby airguns with a maximum sound pressure of 203 dB at 1 m (McCauley et al., 2003). Furthermore, when exposed to 30 minutes of ship sounds ranging from 128 to 162 dB three species of European freshwater fishes showed increased levels of the stress hormone cortisol. These results suggest that even non-lethal noises may have significant impacts on the operation of mariculture facilities in the GOM.

The perceived as well as the real ecological impacts, both from the oil infrastructure on the fish and from the fish to the larger environment, are critically important for OOA. OOA is capital intensive and is most likely to succeed if the resulting fish can be marketed as healthy and environmentally responsible. Given that commercial and recreational fisheries exist in the most heavily industrialized sections of the GOM, it seems reasonable to assume that the ecological impacts of drilling on mariculture would be minimal or mitigable. Regardless of their actual environmental impacts, if oil and gas platforms are seen as dirty or polluted by the public, platform based OOA will have difficulty.

5.5. Open Ocean Mariculture Projects

There are several OOA projects in operation around the world (Skladany et al., 2007). The vast majority of these projects are not associated with platforms. A comprehensive review of these projects can be found in Skladany et al., (Skladany et al., 2007) or Halwert et al. (Halwart et al., 2007). Four offshore projects are located in the U.S. including two farms in Hawaii (Hukilau

Foods and Kona Blue Water Farms), one in Puerto Rico (Snapperfarm) and one in New Hampshire (University of New Hampshire Atlantic Marine Aquaculture Center). None of these use platforms as offshore bases.

Snapperfarm began operating in 2002. They originally planned to raise cobia and red snapper, but after initial problems with red snapper they began stocking only cobia. Snapperfarm operates in collaboration with the University of Miami which provides fingerlings for the operation. They currently operate three, 3,000 m^3 submerged cages and have successfully harvested several crops at a rate of a few tons per week. The depth at the site is 25 to 30 m (Benetti et al., 2007; Benetti et al., 2008).

Kona Blue Water Farms operates an integrated hatchery and offshore grow out system for Almaco jack (*Seriola rivoliana).* They are the only commercial operator with an integrated hatchery. They market their product as environmentally sustainable and healthy with low levels of mercury and their fish was recommended as a good alternative to other farmed yellowtail species by the Monterey Bay Aquarium. Their site is less than one km offshore but in water 60 m deep. They currently produce approximately 12 tons of fish per week which is now sold in restaurants across the U.S. (Kona Blue, 2008).

Hukilau Foods (formerly Cates International) developed from a research project conducted by the University of Hawaii. Hukilau produces about 900,000 pounds (about 400 metric tons) of moi per year (as of 2007). Their four 3,000 m^2 cages are 3.2 km offshore in approximately 50 m of water. Hukilau intends to expand production to 1.5 million pounds per year (680 metric tons) and to develop an integrated fish hatchery capable of producing 10 million fingerlings annually (Hukilau Foods, 2007).

The University of New Hampshire Open Ocean Aquaculture program raises Atlantic cod, halibut, haddock, and flounder as well as blue mussels in an area 10 km off the coast of New Hampshire. The depth in the area is 60 m. Although they do sell their products, they are a research institute and not a commercial facility. They currently use two, 3,000 m^2 cages but have also tested several other cage designs and they have developed a remote feeding buoys that can hold and distribute 20 tons of feed (Atlantic Marine Aquaculture Center, 2007).

5.6. Platform-Based Mariculture Projects

5.6.1. International Platform-Based Projects

Spain has a well developed offshore and near shore mariculture industry which developed in part due to a lack of sheltered sites along the coast (Cardia and Lovatelli, 2007). Spain also has one of the few operational platform based offshore projects in operation. Marina System Iberica (MSI) built four floating platforms along the Mediterranean coast. These platforms are steel structures that are moored to the seabed. Nine cages are attached on each floating platform with a total volume capacity of 18,000 m^3 allowing production of 450 tons of fish a year. The freeboard of the platform can be adjusted to adapt to different sea climates through the ballasting system of its vertical columns. Four small buildings are located over the platform to hold the power generator, biological laboratory, feeding warehouse and crew dormitory. While this design is revolutionary in that in allows crews to permanently man an offshore fish farm, the structure is not fixed to the seabed.

Since 1998, there have been three platform-based mariculture operations in Northern Hokkaido, Kumamoto, and Ehime. The Northern Hokkaido platform controls five cages, each 6,000 cubic meters (20×20×15 m). The feeding and monitoring systems are controlled by a computer which allows the onshore base to operate the daily feeding work remotely. Electronic power required by the operation is delivered by transmission wire on the seabed. This operation produces 80 tons of salmon and 160 tons of trout yearly. The North Hokkaido platform experienced a magnitude-6 earthquake and 3-meter waves after it was established, but no damage was incurred.

5.6.2. Texas Sea Grant Project

There have been several attempts at using oil and gas platforms for mariculture in the U.S. (Table E.2), but thus far, none have reached commercial status. In the early 1990's, the Texas Sea Grant program started the first platform based mariculture operation in the Gulf of Mexico. Texas Sea Grant scientists used an Occidental Petroleum platform as an offshore operations base to grow redfish in a net-pen (Waldemar Nelson International, 2001). During its operation, storms damaged some of the cages and fish escaped. According to the Sea Grant reports, the fish cost $22 per pound to raise and had a market value of $3.50 per pound (Gulf of Mexico Fishery Management Council, 2007). The project was eventually abandoned.

5.6.3. SeaFish Mariculture LLC

In the late 1990's, Seafish Mariculture LLC proposed to utilize gas platforms offshore Texas for an OOA operation. SeaFish Mariculture operated from 1997 to 1999. The first group of red drum fingerlings was stocked on November 30, 1997. The platform was staffed in rotation by two, 2-person teams who lived on the platform and were transported to and from the platform via helicopter. Shell continued to operate the platform over this period.

SeaFish Mariculture successfully raised red drum from 3-inch hatchery-raised fingerlings to market-size fish in a growth cycle of less than 12 months. However, the project encountered a number of difficulties including losses due to storms and cage movements necessitated by the needs of the oil and gas operator. In July 1999, SeaFish Mariculture notified NOAA Fisheries Service that it planned to terminate the project due to the needs of the operator to increase gas production at the site (Gulf of Mexico Fishery Management Council, 2007).

5.6.4. Gulf of Mexico Offshore Aquaculture Consortium

In February 2000, the Gulf of Mexico Offshore Aquaculture Consortium (OAC) was formed to create a university-based interdisciplinary research program to study the social, environmental and technological issues that impede mariculture development in the Gulf of Mexico. The OAC planned to place a cage adjacent to an oil and gas platform but did not plan to connect its cage directly to the platform or even to utilize the platform directly. OAC explained that the site selection was determined to minimize the number of potential user conflicts while increasing the protection to the cage.

In May 2000, a Sea Station cage manufactured by Ocean Spar Technologies was assembled on the coast of Mississippi. The cage was towed to its mooring position, near the Chevron 990 platform, approximately 40 km south of Pascagoula, MS, in 25m of water. According to the research plan, the cage would remain empty during the first year so that engineering and environmental monitoring could be conducted. In October 2000, the research cage broke free of its mooring and was carried to the northern end of Chandelier Island 10 km away (OAC, 2002).

In July 2002, OAC redeployed its cage and adopted an improved mooring system developed by researchers at the MIT Center for Fisheries Engineering Research. OAC planned to stock the cage with red drum fingerlings (OAC, 2002). After July 2002, OAC no longer released news about this project, and according to correspondence from OAC, the project did not work as well as expected and the cage has been removed from the water.

5.6.5. Grace Platform Project

In 2003, Hubbs-SeaWorld Research Institute proposed a fish hatcheries and marine stock program for the Grace Platform offshore California. The 3-year research program was designed to test the feasibility of using offshore platforms as operational bases for the sustainable development of mariculture. The project was supported by Chevron Environmental Management Corporation, which funded the institute's start-up costs and offered $10 million to run the operation for three years. According to some reports, Chevron hoped to avoid the expense of removing the Grace Platform by sponsoring this mariculture project (James and Slaski, 2006).

The Grace Mariculture Project planned to suspend four, 125,000 m^3 cages off the platform. They planned to raise white sea bass, striped bass, California halibut, California yellowtail, bluefin tuna, red abalone, and mussels. In 2006, the Grace Mariculture Project had to abandon operations because of the owner's plans to develop an LNG gasification facility at the site (Hubbs-SeaWorld Research Institute, 2009).

5.6.6. GMIT Project

Gulf Marine Institute of Technology (GMIT) is a nonprofit research institute that partnered with Biomarine Technologies and Biomarine Fuel. In September 1998, GMIT was granted approval from the Texas General Land Commissioner to use a multi-platform oil and gas complex along the coast between Freeport and Corpus Christi (Poruban, 2000). However, in October 1999 the Texas General Land Commissioner reversed course and ordered GMIT to remove the platforms (Poruban, 2000) resulting in lawsuits that were settled in GMIT's favor in late 2005. The company has not yet placed fish in the water but is still planning to do so.

According to GMIT, the operators have invested $6.2 million for the acquisition of marine vessels and the platform complex. The platform removal liability bond for this project is $2.6 million (Poruban, 2000). GMIT and Biomarine hope to eventually install 76 cages and realize an annual net income of $52 million. The company has estimated the project would create 1,100 jobs (GMIT, 2007) (Table E.3).

5.7. Site Selection

Site selection is among the most important factors that can influence the ecological impacts and profitability of an offshore mariculture operation. GIS based models for identifying areas that are most suitable for offshore mariculture operations have been developed (Longdill et al., 2008). Here we describe in a qualitative way the factors that influence site selection and their prevalence in the GOM.

5.7.1. Topography

Topography is a major influencing factor in determining the operational suitability of offshore sites. Deepwater (30 or more meters) allows for the use of submerged cages which decrease the impact of waves (Huang et al., 2008). Many of the currently operational offshore sites are in water 50 to 60 m deep (all except Snapperfarm which is in 25 to 30 m of water). The continental shelf of the GOM slopes gently from the shore to a depth of about 200 m, approximately 100 to 200 km offshore. Most of the existing oil structures are in this region. However, there are large areas with offshore infrastructure in which water depths are less than 25 m (Figure E.3). As a result, mariculturists might have to go further offshore to find suitable infrastructure. Ideally, mariculturists would find sites that were both close to shore and in relatively deep water (over 30 m).

The significant wave height impacting an area is also important as it can lead to stress on cages and may be impacted by topographical features such as reefs, islands, or peninsulas. These features can extend the duration of favorable weather windows, allowing more time for on-site operations, decrease the severity of extreme weather events and could also be associated with lower significant wave heights (Turner, 2000). Examples of these areas in the offshore GOM might include artificial reefs and the western side of the mouth of the Mississippi.

Obviously, platforms close to shore will be preferred over those further from shore. For non-platform-based projects distance to shore and ports will be of paramount importance for logistical reasons; this requirement is not as important for platform-based projects since the platform will allow for less frequent supply trips from shore. However, the supply vessels used in the oil and gas industry travel slowly and use large amounts of fuel. A small supply vessel might travel at 10 knots and use 50 to 100 gallons of diesel per hour, therefore, fuel and crew costs can be significant. In a study of offshore cod aquaculture, Jin (Jin, 2008) found that moving a hypothetical operation from 5 to 10 miles offshore decreased the average present value in three scenarios by $1.77 million, and moving from 5 to 25 miles offshore decreased average present value by $5.76 million.

5.7.2. Water Exchange

Because mariculture operations depend on water currents to supply oxygen and to remove wastes, fish farmers should locate their cages or net-pens where there is pollution-free high tidal water flow. However, dangerously strong current may cause high stress to fish and hazards to mariculture facilities. Optimum average current speeds will vary depending on the species of fish being farmed, but generally lie within the range of 0.1 to 0.5 meters per second (Petrell and

Jones, 2000; Reidy et al., 2000). Average speeds beyond this range may force fish to expend more energy swimming, thus reducing growth rates, and may also impact the structural integrity of the cage (Huang et al., 2008). Average speeds below 0.1 meters per second may not provide adequate water exchange. Thus, there is a tradeoff between growth rate and water circulation in site selection (James and Slaski, 2006). Current velocities at the surface along the Texas-Louisiana shelf are generally 0.2 to 0.3 m/s, within the optimal range (Louisiana Department of Natural Resources, 2005; Johnson, 2008). The weakest currents in the area of oil and gas infrastructure occur off the Louisiana coast near the Texas boarder while the strongest occur just to the west of the mouth of the Mississippi (Johnson, 2008). Importantly, there are areas of appropriate currents just off the Texas coast from Matagorda Bay to Corpus Christi; this is the area in which Biomarine and GMIT are basing their operation.

5.7.3. Temperature

Optimal temperatures vary among species but significant temperature fluctuations will adversely impact mariculture operations. In general, offshore sites are known to experience more stable temperature regimes than those found inland, thus reducing the probability of extreme fluctuations. Additionally, the use of native, non-migratory species will help to ensure that a proposed site has species specific optimal temperatures. Cobia, perhaps the best candidate species for open ocean aquaculture in the GOM, is native to the Gulf.

5.7.4. Salinity

In coastal regions salinity can be significantly influenced by nearby freshwater discharges. However, salinities are relatively constant in offshore sites. Most sites in the GOM will probably have stable and appropriate salinities for most pelagic species. All of the federal offshore oil and gas platforms are in areas that are not significantly affected by freshwater inputs.

5.7.5. Oxygen

Adequate oxygen levels are critical for all fish species. Some offshore locations adjacent to zones of upwelling can routinely experience oxygen levels as low as 3 mg/L (Rabalais et al., 2002). Furthermore, algal blooms can cause significant decreases in dissolved O_2. For example, the annual algae bloom in the Gulf of Mexico reduces O_2 concentrations to as low as 0.5 mg/L (Rabalais and Turner, 2006). Long-term advance monitoring must indicate a minimum of 90 percent O_2 saturation and/or O_2 concentrations of 7 mg/L.

5.7.6. Algae Blooms

The experience of the European mariculture industry indicates that algae blooms and large jellyfish populations may have serious negative impacts on farmed fish. Both of these factors can negatively influence the survival and growth rates of fish.

In general, algal blooms are caused by large nutrient inputs into aquatic ecosystems. These algal blooms can be harmful to mariculture in one of two ways. First, algae can release toxins, for example ciguatoxin, which can bioaccumulate and reach high levels in fish. If fish with high levels of toxins are consumed by humans they can cause severe illness. *Gambierdiscus toxicus*, the dinoflagellate that contains ciguatoxin, is generally absent from the GOM; however, oil structures have been shown to provide a hard substrate which harbors *G. toxicus* (Villareal et al., 2007). Similarly, *Karenia brevis*, the dinoflagellate that causes neurotoxic shellfish poisoning and respiratory disease in humans is also known to occur in the GOM (Stumpf et al., 2003).

Secondly, when algae die they sink to the ocean bottom and decompose. This decomposition uses oxygen, which depletes the concentration of oxygen in the water and can cause an anoxic zone. Each summer, a 20,000 km^2 hypoxic zone develops in the GOM due to the nutrient input from the Mississippi river (Rabalais et al., 2002; Rabalais and Turner, 2006). Fish generally flee this zone; however, Pichavant et al. (2000) demonstrated experimentally that turbot exposed to hypoxia grew significantly slower than turbot exposed to normal oxygen conditions. Thus, fish enclosed in cages in this area would be unlikely to grow as well as fish elsewhere in the GOM. This zone overlaps with many of the fixed platforms in the GOM and would have to be considered before any maricultural activity commenced (Figure E.4).

5.7.7. Jellyfish Blooms

Jellyfish blooms can damage the gills of farmed fish leading to mortality and decreased growth rates for surviving fish. The causes of jellyfish blooms are currently under investigation, but one potential cause could be the warming of the oceans (Purcell et al., 2007). Ocean temperatures will continue to increase in the coming decades (IPCC, 2007), therefore, the potential for jellyfish blooms, and the possibility of excluding them from net-pens, should be considered. The number of jellyfish have increased in the Northern GOM since the 1990’s and they have become distributed further offshore (Graham, 2001). In the summer of 2000 an invasive species, *Phyllorhiza punctata*, was first cited in the Northern GOM (Graham et al., 2003).

5.7.8. Hurricanes

Open ocean mariculture in the GOM will be impacted by hurricanes. Figure E.5 shows the tracks of the category 3, 4, and 5 hurricanes that impacted the GOM between 1983 and 2004. Since OOA operations will require many years (at least decade) to earn back the initial capital investment, operators should plan on dealing with one major hurricane and several smaller hurricanes and tropical storms. These storms can damage cages and can topple piled structures. Damage to cages can be mitigated by submerging cages in deep water. Damage to piled structures usually occurs when waves reach the height of the deck. The requirements for minimum deck heights have become more stringent over time. This, along with the subsidence that has occurred along the continental shelf, results in older structures being at a greater risk for catastrophic failure than younger structures (Laurendine, 2007). Figure E.6 shows the distribution of existing fixed platforms by age. Most older platforms are nearshore while many of the newer platforms, especially those outside of otherwise unacceptable areas, are far offshore.

5.7.9. User Conflicts

One of the more difficult aspects of using platforms for mariculture will be to manage user conflicts in the GOM. The GOM has a great deal of ship traffic from both cargo ships and commercial fishermen. Ship traffic is most densely concentrated close to the several ports that are heavily used as bases for offshore service vessels (especially Fourchon) and near the mouth of the Mississippi. While platforms are not directly in ship lanes, they may be located nearby and noise from passing ships could impact fish growth (Figure E.7).

5.7.10. Proximity to Markets

The GOM does have some significant advantages over commercial OOA projects now in operation. The three commercial OOA operators are located in Puerto Rico and Hawaii, far from many of their consumers. OOA operators in the GOM would, conversely, have nearby markets in New Orleans, Houston, Atlanta, Dallas, San Antonio, Mobile, Pensacola, and Baton Rouge, reducing the transport costs and times for their products.

5.7.11. Suitable Platforms

Using the information discussed in sections 5.6.1. through 5.6.10. and the GIS maps in Figures E.3 through E.7, we apply exclusion techniques to select platforms that might be most suitable for OOA use. These, along with bathymetry contours, are shown in Figure E.8. We selected only platforms outside of hypoxia zones, in greater than 25 m of water, and outside of shipping lanes. Out of the 2,427 fixed platforms, only 191 may be appropriate for OOA use.

5.8. Removal and Reuse of Platforms

Given the constraints of site selection, liability and co-use with oil and gas operators, it may be more feasible for mariculturists to attempt to reuse decommissioned platforms. In the oil and gas industry it is not uncommon for platforms to be brought to shore to be refurbished and reused, saving on the costs of new fabrication (Kaiser and Pulsipher, 2007b). Re-use opportunities in oil and gas are often constrained due to the specific requirements needed for facilities (number of slots, deck weight, jacket height, number and capacity of cranes, crew accommodations). The mariculture industry is likely to be more flexible in its needs and more likely to reuse refurbished platforms.

The reuse of refurbished platforms would remove liability concerns from oil and gas operators and might decrease liability for mariculturists. The reuse of refurbished oil and gas platforms would also expand potential areas for site selection, especially to the eastern GOM and the coast of south Texas, which has relatively few platforms. Using refurbished platforms would eliminate concerns, real or perceived, about the impacts of raising fish adjacent to oil and gas production and their resultant pollution. Finally, using refurbished platforms would maintain the total amount of hard substrate in the GOM. While the ecological community living on and around the platform would be destroyed during the process of removing and refurbishing the platform, the replacement of that platform elsewhere in the GOM would lead to the eventual recolonization of the structure.

5.9. Conclusion

Platform-based mariculture is an attractive idea for the GOM as it provides a potentially sustainable food source while also providing an outlet for no longer useable oil and gas platforms. However, there are a number of disadvantages and constraints on site selection, which make platform-based OOA relatively unattractive to both oil and gas operators and mariculturists at the present time.

Of all of the hurdles to platform-based mariculture, liability may be the greatest. Removing a platform can be expensive under ideal conditions, and if the structure is toppled by a hurricane, it can be financially ruinous. If a hurricane destroyed a platform-based mariculture operation, it would not only bankrupt the mariculture operator, but after collecting the value of any assets and bonds from the mariculture company, the federal government would hold the original operator liable. This provides a disincentive to oil operators to sell structures to mariculturists.

Much of the GOM is not well suited for the use of oil and gas infrastructure in mariculture operations. This is most notable along the shallow continental shelf offshore western Louisiana and eastern Texas from Timbalier Bay to Galveston. These areas are unlikely to be suitable for offshore aquaculuture due to their shallow water and susceptibility to low dissolved oxygen levels. However, there are more suitable areas to the south and west of the mouth of the Mississippi, and offshore Texas from Port O'Connor to Corpus Christi. Both of these areas have relatively strong currents, high minimum dissolved oxygen and deep water. There is also an area to the south and west of Mobile Bay that has relatively deep water and potentially acceptable dissolved oxygen levels, but has weaker currents than elsewhere in the Gulf. If OOA develops in the GOM it is most likely to occur in these areas.

Platform use would be best suited to cases in which near shore sites are somehow constrained. For those interested in the development of an OOA industry in the U.S., it may be more prudent to select sites relatively close to shore which would not require platforms. Only when these sites are developed will OOA be likely to spread further offshore, potentially necessitating the use of platforms.

6. ECONOMIC FEASIBILITY ASSESSMENT FOR PLATFORM-BASED MARICULTURE IN THE GULF OF MEXICO

In the Gulf of Mexico, there has been strong interest over the years to utilize the existing oil and gas infrastructure to facilitate mariculture operations. The economics of such plans, however, are usually highly uncertain and subject to a large degree of technical risk. The purpose of this chapter is to evaluate the economic feasibility of platform-based mariculture operations in the Gulf of Mexico. We first review the available literature on the costs of offshore aquaculture. A scenario-based economic model is then developed to explore the feasibility of platform-based cobia aquaculture. We end with remarks on the viability of an offshore aquaculture industry in the U.S.

6.1. Prior Studies of Offshore Aquaculture Costs

There have been surprisingly few studies of the economic costs of offshore mariculture and a limited amount of data collected and published. Data from previous cost studies is shown in Table F.1. Most of the studies cited derive from theoretical estimates. As a result, the estimates differ markedly depending on the assumptions used in developing the model and the species selected and the type of offshore support system.

The accuracy of the models is dependent on their assumptions and, since there is little available empirical data to inform these assumptions, it is difficult to draw conclusions about their validity. The assumptions of the models vary widely (Table F.2). In some cases, like feed conversion rate (FCR), this could be due to the species modeled; however, we might expect other assumptions, such as the cage cost to be roughly similar among models. Instead, the cage costs vary from 27 to 89 $\$/m^3$.

Posadas and Bridger (2003) follow Bridger and Goudey (Bridger and Goudey, 2004) and model a system that uses a purpose built aquaculture support vessel. They assumed a barge costs $1.5 million. Likewise, Ryan (Ryan, 2004) assumed that operators would spend $900,000 on each of three feed barges which would each store 600 tons of food. These capital costs are roughly similar to the cost of an offshore platform.

6.2. Methodology

We built two net present value (NPV) models of the costs of a hypothetical offshore cobia culture system. Cobia is a fast growing species that is currently being grown in an open ocean aquaculture application by Snapperfarm in Puerto Rico. There has been one previously published NPV study of cobia (Posadas and Bridger, 2003). However, since then a great deal of information about cobia growth and culture has appeared.

We built two conceptually similar models with assumptions that differ principally in the way in which productivity is estimated. In the first model we used 2003 data from Snapperfarm to estimate a total production of 3.78 kg/m^3 per year. Snapperfarm built its first two cages in 2002. Their target stocking density may not have been reached in 2003. Thus, adopting the fish density from the data reported in 2003 may underestimate the actual productivity of cage culture (Gulf of

Mexico Fishery Management Council, 2007). To account for these potentially low production values, we developed a model in which we adjusted the initial stocking density and used per fish growth rates to determine production levels. Throughout the remainder of this chapter, we refer to the two models as model A and model B. We also considered pessimistic, optimistic and expected scenarios for both models.

NPV is the difference between the present value of cash inflows and the present value of cash outflows. This measure is commonly used in capital budgeting to analyze the profitability of an investment or project and compares the value of a dollar today to the value of that same dollar in the future, taking inflation and returns into account. If the NPV of a prospective project is positive, it should be accepted; otherwise, the project should be rejected. The NPV equation is:

$$\text{NPV} = \sum_{t=1}^{T} \left[\frac{\text{Annual Net Profit}}{(1 + \text{Cost of Capital})^{t}} \right] - \text{Initial Investment}$$

$$= \sum_{t=1}^{T} \left[\frac{(\text{Revenue} - \text{Operating Costs} - \text{Depreciation}) \times (1 - \text{Tax Rate}) + \text{Depreciation}}{(1 + \text{Cost of Capital})^{t}} \right] - \text{Initial Investment}$$

6.2.1. Model Assumptions

The assumptions of the models are listed in Table F.3. We model a hypothetical platform system with a variable number of 39,270 m^3 cages. The system consists of a single platform which supports 2, 4, or 8 cages. We assume that there is no ongoing oil or gas activity, and that the aquaculture operator takes full responsibility for the platform and its associated liability. We assume that the number of workers scales linearly with the number of cages, and the capital costs associated with vehicles and vessels is constant. We assume just one manager and one supervisor regardless of the number of cages. We assume variable but high costs of capital commensurate with an unproven and high risk industry. We also assume variable yearly efficiency gains that decrease operating costs by a set percentage each year. A variable contingency capital cost is assumed which serves to increase capital costs by a small percentage in order to factor in overlooked capital expenditures.

Data on cobia come from (Waldemar Nelson International, 2001; Posadas and Bridger, 2003; James and Slaski, 2006; Benetti et al., 2007; Hendrix, 2007; Keithly, personal communication, 2007; Aquaculture Center of the Florida Keys, 2007; Benetti et al., 2008; BioMarine Technologies Company, 2000). We assume that cobia grows quickly, reaching 4 to 6.5 kg one year after hatching (GMIT, 2006; Aquaculture Center of the Florida Keys, 2007; Benetti et al., 2008). A variable FCR of 1.3 to 1.7 is assumed. In both models the cobia are 20 grams upon stocking. Shipment of cobia fingerlings generally occurs at 1.5 grams, and there is a 20 day period between shipment and stocking in which cobia would be housed in tanks either on-shore or on the offshore platform.

We assume that the operator is required to deposit \$200,000 per year into an escrow account to cover decommissioning costs. Similarly, we assume an insurance cost of \$200,000 per year and that the value of the infrastructure depreciates linearly with no salvage value. A feed price of 1000 \$/mt (Table F.4) and a variable cage cost described in Table F.5 are also assumed.

6.2.2. Model A Calculations

In 2003, Snapperfarm Inc used 2 Sea Station cages, each 3,000 cubic meters, to produce 50,000 pounds fish (Gulf of Mexico Fishery Management Council, 2007). The production per cubic meter is approximately:

$$\frac{50{,}000 lbs}{3{,}000 m^3 \times 2} = 8.33 lbs/m^3 \ \ (3.78 kg/m^3)$$

In Model A, the production density is used to back calculate the number of fingerlings needed, given the basic model assumptions. The number of fingerlings needed per year is calculated by:

$$\frac{\text{Expected production per Year}}{\text{The Annual Growth Rate of the Species}} \times \frac{1}{\text{Survive Rate}}$$

Feed cost is calculated as follows:

$$\text{Feed Cost per Kg of Products} = \frac{\text{Food Conversion Ratio} \times \text{Price per Kg of Feed}}{(1 - \text{Uneaten Feed Ratio}) \times \text{Survival Rate}}$$

The results of this calculation are shown in Table F.6. The total initial investment and annual operating costs and their components are shown in Tables F.7 and F.8, respectively. In the three scenarios, the feed and labor are the two most significant components of the operation costs, in total accounting for a share ranging from 44 to 63 percent. The remaining share is almost entirely fixed costs. Among the fixed costs, maintenance costs of equipment and the platform account for the largest portion, in total $530,000 per year, or approximately 20 percent of total operation costs.

6.2.3. Model B Calculations

In Model B, we stock the cages with a specified number of 20 gram fish. These fish grow to either 4, 5, or 6 kg in one year with a variable survival rate. The production is given by the formula:

Production (kg) = Number Fingerlings x Survival Rate x Average Final Weight (kg)

In Model B, the feed requirements are calculated as:

$$\text{Feed Requirements (kg)} = \frac{\text{Production (kg) * FCR}}{\text{(1- Uneaten Food Ratio)}}$$

The total initial investment and annual operating costs and their components are shown in Tables F.7 and F.8, respectively.

6.3. Results

6.3.1. Model A Results

Based on annual production and ex-vessel price, annual revenue can be calculated (Table F.9). Comparing estimated annual revenue to annual operation costs, we find that in the pessimistic and the expected scenarios the operating financial input cannot offset the output, indicating that the hypothetical platform-based operation will not be profitable over ten years. In the optimistic scenario, the estimated annual revenue is greater than the operation costs (compare Tables F.8 and F.9).

The NPV of our hypothetical platform-based mariculture operation are also shown in Table F.9. All NPVs of the three scenarios are negative. In pessimistic and expected scenarios, negative cash flows run through the entire operational life. Although in the optimistic scenario operating activities contribute a positive cash flow, this is inadequate compared to the initial investment to make NPV positive. The results indicate that, under the aforementioned assumptions, the investment on platform-based mariculture project is economically infeasible.

6.3.2. Model B Results

The results from Model B are significantly more positive than the results from Model A. In the expected and optimistic case the NPV is positive suggesting that platform-based cobia mariculture is economically attractive under these circumstances (Table F.10). Under optimistic assumptions, NPV is strongly positive with annual net cash flows (after taxes) of over $18 million. With pessimistic assumptions, the model still generates positive net cash flows over its lifetime, but these cash flows are only $257,000 per year (before discounting) and not enough to make up for the $10.8 million initial capital expenditure.

6.3.3. Rent Scenario

Based on the expected Model A scenario, we developed a rent scenario to examine the economic feasibility when the hypothetical operation rents the necessary vessels and vehicles instead of purchasing them. This causes capital costs to decrease and operating costs to increase. The rent fees for every 10,000 tons production are assumed to be $2 million for vessels and $200,000 for vehicles. In the rent scenario, we also assume that the hypothetical operation receives a "free" platform from an oil and gas company, but that the mariculture operators are required to pay $200,000 per year towards decommissioning (alternatively, this could be understood as the mariculture operation renting a platform from an oil and gas operator for $200,000 per year without assuming decommissioning liabilities).

The comparison of operation performances of the rent scenario and expected scenario are shown as Table F.11. In the rent scenario the hypothetical operation reduces its capital costs but increases operating costs to maintain its business. Although this operating strategy improves the NPV of the operation performance, it increases the operating costs and does not make the operation profitable.

6.4. Limitations of This Analysis

This analysis, like the analyses cited above, is limited by available data. There is little available data on fingerling costs, and feed prices had to be estimated from revenue and production data from major suppliers. Nonetheless, our assumptions are generally consistent with those of previous studies.

It is difficult to find reliable information on the insurance premiums for offshore mariculture operations since commercial operations do not yet exist in the U.S. and since insurance premiums in the GOM region have increased significantly after Hurricane Katrina. The assumed insurance premium may be different from the real value. However, as illustrated in Table F.12, the NPV is relatively insensitive to changes in insurance costs.

We did not include costs associated with growing fingerlings from their 1.5 g shipping weight to their 20 g stocking weight. Instead, we simply assumed the cost of the stocked fingerling was \$2. Given the number of fingerlings required and the risk associated with shipment, it may be advantageous for cobia mariculturists to vertically integrate their operations, at least with respect to larvae hatching and growth. Fingerlings could then be grown to 20 grams onshore before transport to offshore cages. It is possible that this process could cost more than \$2 per fingerling. However, using the break even analysis of model B we found that under expected conditions the price per fingerling would need to exceed \$6.65 in order to make NPV equal to zero. Economic analysis of other fish species indicates that the costs of raising fingerlings may be well below \$2 (Kam et al., 2003), leaving significant money available to meet the costs of growing cobia to 20 g over a 20 day period (Benetti et al., 2007).

It is likely that the economic variables used in this analysis might change. Most importantly, the prices of harvested fish may either decline or increase depending on global trends and marketing. Between 1990 and 2005, the prices of fish and seafood raised by the aquaculture industry declined while the prices of most other seafood increased (Anderson and Shamsak, 2008). Thus, it is plausible to argue that cobia prices might increase as supplies from commercial fisheries are exhausted, or decrease if cobia production outpaces demand. Furthermore, open ocean aquaculturists could market their products as sustainable, thereby yielding higher prices.

Finally, it is important to note the economies of scale assumed in the model. In general, the submerged cages used so far in open ocean mariculture projects are approximately 3000 m^3. The cages we envision are almost 40,000 m^3 (a sphere with a diameter of 42 m). Ocean Farm technologies manufactures an AquaPod submersible cage with 9,800 m^3 of volume (a sphere with a 27 m diameter), OceanSpar Technologies makes an AquaSpar cage with 40,000 m^3 of space and the Grace Mariculture project envisioned using 125,000 m^3 cages (Gulf of Mexico Fishery Management Council, 2007). However, it does not actually matter what sized cages are used in our models; as long as the total cage volume and the cost per m^3 are constant, our model will yield similar results for 10 4,000 m^3 as for one 40,000 m^3 cage.

6.5. Discussion

Table F.12 shows the points at which the NPV of Model A and B is equal to zero for selected parameters. In each case, we changed a single parameter and left all others at their default levels. As illustrated in the table, small changes in a variety of factors can make the Model A optimistic scenario profitable. Conversely, small changes in a number of parameters can make the Model B expected scenario unprofitable.

Table F.13 and Figure F.1 illustrate the sensitivity of the model. Table F.13 compares the sensitivity of model B to changes in parameter values by comparing the change in NPV per unit change in parameter values. It is clear that the model is very sensitive to initial stocking densities. This is also seen in Figure F.1.

In commercial aquaculture operations there is likely to be a tradeoff between FCR, stocking density, growth rate and survival rate. As operators increase stocking density, FCR will increase while growth rate and survival will decrease. Figures F.2 through F.4 delineate the break even points between stocking density and FCR, growth rate and survival using Model B, expected case. In each case the relationships are non-linear with large changes in the slope of the relationship around a stocking density of 0.1, the density chosen in the expected case of this model. This demonstrates the precarious nature of investment in offshore aquaculture. Additionally, the graphs show the more positive opportunities associated with higher stocking densities. If mariculturists can increase stocking densities to 0.2 to 0.3 kg/m^3 then there is much greater opportunity for positive NPV.

Of the six models discussed in this paper, the pessimistic case of model B may be the closest to the current reality for offshore cobia culture. In 2007, Snapperfarm produced 100 tonnes of cobia using approximately 9,000 m^3 of cage volume (Benetti et al., 2008). The total density would have been 11.11 kg/m^3 comparable to the density of 15 kg/m^3 used in the pessimistic case of Model B. Importantly, Snapperfarm operates at a much smaller scale than our hypothetical model. This combined with the negative NPV associated with the Model B pessimistic case suggests that cobia culture may not be economically feasible.

6.6. Conclusions

Our analysis illustrates the sensitivity of platform-based mariculture to changes in stocking and production density. The primary differences between Models A and B are in the way in which production is calculated. In Model A, production is based on empirical data, but we suspect the data may not represent the true situation due to the nascent nature of the industry. Conversely, production in Model B is based on theoretical growth and survival data, with stocking densities chosen to produce realistic final densities. These densities are 5 to 10 times the final densities used in Model A and the results from Model B give a much rosier picture for the future of offshore platform-based mariculture.

Platform-based offshore mariculture carries significant risks. Our models indicate operations may or may not be profitable depending on the assumptions used. The assumptions that we used generally cover the range of expected real values. Thus, investment in offshore mariculture is risky. If the early attempts at offshore cobia mariculture can demonstrate yields of over 20 kg per cubic meter of cage volume then the chances of a commercially successful venture grow significantly.

7. COMPARISON OF OFFSHORE WIND POWER DEVELOPMENT IN EUROPE AND THE U.S.

In the U.S. there has been significant interest in the development of an offshore wind energy industry. Increasing coal, natural gas and oil prices, an increasing reliance on foreign sources of oil, and increasing concerns about global climate change, have made domestic, renewable and low carbon sources of energy particularly attractive to policy makers. As of mid 2009, no offshore wind farms are under construction in the U.S., but resource assessments are ongoing at Cape Cod, Massachusetts, and Galveston, Texas.

We begin this chapter with a discussion of the patterns of offshore development in Europe and compare to the proposed developments in the U.S. We discuss the current status of offshore wind plans and testing in the U.S. and reasons for the cancellation of some projects. The policy drivers of the offshore wind energy industry in Europe are compared to the drivers in place in the U.S. We conclude with a discussion of the effects of potential U.S. policies on the offshore wind industry.

7.1. Introduction

Wind energy is the alternative energy source with the most realistic chance to displace large amounts of fossil fuel combustion. Over the past several years, the onshore wind energy industry has seen explosive growth, both in the U.S. and around the world (Figure G.1). In Europe, the growth in the onshore wind energy industry has been supplemented with growth in the offshore industry (Figures G.2 and G.3) which at present represents 1.8 percent of the total installed European wind capacity.[16] The first offshore wind farm began operating in 1991; by the end of 2007 there were approximately 1,200 MW of installed capacity. By 2009 the wind capacity in Europe is expected to grow by another 1,500 MW, and by 2015, the rate of growth of the European offshore industry is expected to be 1,700 to 3,000 MW per year (EWEA, 2007).

There are a number of reasons why offshore wind development has lagged behind in the U.S. Both the offshore wind resources and the governmental subsidies for offshore wind power differ in Europe and the U.S., and it is not clear if offshore wind power will be profitable in the U.S. in the short term. In general, wind speeds increase further from shore. This increases the electrical generation of turbines, but operating in the offshore environment is significantly more expensive and risky than onshore, and for offshore wind development to succeed, a combination of events must hold. The revenue potential from offshore wind must exceed the associated costs and risks, federal involvement in advancing renewables through regulatory programs and economic incentives must be in place, state involvement through renewable portfolio standards must continue, and public acceptance of offshore wind farms must occur.

[16] Due to the higher wind speeds over the ocean, offshore wind generates a disproportionate percentage (3.3 percent) of the wind generated electricity in Europe (EWEA, 2007).

7.2. Offshore Wind Energy Development in Europe

7.2.1. European Wind Farms

There are a number of operational (Table G.1) and approved but not constructed offshore wind energy projects in Europe (Table G.2). Denmark and the UK have the largest share of operational offshore capacity. Germany has the largest share of planned capacity, but has no significant operational wind farms (Table G.3).

7.2.2. Trends in Europe

One of the clearest trends in the offshore wind industry in Europe is the increasing size of wind farms (Figure G.4). Additionally, developments have progressed into deeper water, further from shore and have adopted larger turbines (Figures G.5 - G.7).

In Europe, developers and nations began by developing relatively small test projects (10 to 50 MW), then developments of 100 to 200 MW, and are now building or planning projects of 400 to 1,000 MW (EWEA, 2007). This slow development has been intentional and has occurred primarily due to government planning; however, the large farms currently being planned may allow for large cost reductions through scale economies.

The deepest offshore turbines constructed to date have been at Beatrice where turbines were constructed on jacketed foundations in 45 m of water. Excluding Beatrice, the deepest offshore wind farms have been built in water only 10 to 20 m deep, due largely to the constraints of monopole and gravity foundations. Floating wind turbines are being tested in Italy which would allow for development in water over 100 m deep.

The wind farm farthest from shore is Thornton Bank which is 27 km from the Belgian coast. In the near future the Belwind wind farm will be built over 40 km from the Belgian coast. While both Thornton Bank and Belwind are connected with AC cables, the costs of DC transmission are declining which will allow for development further from shore.

The turbine capacity used in both onshore and offshore wind farms has increased over the past decade. Larger turbines are thought to allow for lower operation and maintenance costs, installation, and foundation costs per unit of capacity. The largest turbines used so far have been 5 MW built by REPower and were used in Beatrice and Thornton Bank. However, Enercon has installed a land based 6 MW turbine and Clipper Windpower is planning on building a 7.5 MW turbine.

It is both technologically and economically possible that the next decade will see turbines of up to 10 MW, dozens of kilometers from shore on floating foundations in over 100 m of water.

7.2.3. Industry Structure

European wind farms have been developed by some of the largest energy companies in Europe including Vattenfall (Sweden), Shell (Netherlands), DONG (Denmark), Nuon (Denmark), E.ON

(Germany), and Centrica (UK). Shell, DONG, and Centrica are integrated energy companies that are involved in both electricity generation and oil and gas exploration. Nuon and E.ON are electricity and gas providers, Vattenfall is an electricity provider owned by the Swedish state but active in much of Northern Europe.

In addition to these large energy companies, a few companies specializing in renewable energy have also developed offshore wind farms; however, these companies are generally subsidiaries of large electricity and gas companies. Airtricity, a wind farm developer and subsidiary of a large electricity and gas provider Scottish and Southern Energy, has developed the Arklow Wind farm. Npower Renewables, a developer of wind, hydroelectric and biomass power facilities and a subsidiary of RWE, developed the North Hoyle wind farm. Evelop, a subsidiary of Econcern and a company specializing in the development of renewable power plants, developed the Q7 wind farm and is developing the Belwind Wind Farm.

7.2.4. System Configurations

Most offshore wind farms in Europe have been set up in grid configurations with several hundred meters between adjacent turbines (Figure G.8). However, Middelgrunden was arranged in a single curved line (Figure G.9), and Horns Rev II will be arranged in a series of seven radial lines (Figure G.10). The configuration and design of an offshore wind farm depends on a number of technical factors such as the size of the wind farm, the wind speed, the wake effects of the turbines, the number of turbines, the dominant direction of the wind, the cabling costs, and aesthetics (Manwell et al., 2002).

The turbines in offshore wind farms are almost always linked together with 30 to 36 kV electrical connections. They are then linked to an electrical service platform (ESP). The ESP increases the voltage to over 100 kV for transmission to shore (Figure G.11).

In the future, operators will also have to decide whether or not to permanently man offshore wind farms. So far, this has not been economical given the small size and proximity to shore. However, if wind farms are located a long distance from a port facility and require large amounts of daily maintenance, then developers may decide to staff the wind farms. The Horns Rev II wind farm is expected to be a manned facility.

7.2.5. Installation

Marine construction companies fabricate and install offshore wind farms. Installation is accomplished using jack up barges for pile driving and lifting (Figure G.12). Often several boats are active simultaneously so that one boat is pile driving while another is installing towers or turbines and another may be ferrying equipment from port to the site.

Construction companies have attempted to minimize the work done offshore by assembling as much of the turbines onshore as possible. This speeds the expensive offshore work and reduces the number of lifts required for construction. Among the most common techniques for minimizing offshore work is to connect two of the turbine blades to the nacelle on land “bunny ear” configuration and lift them together onto the tower (Figure G.13).

The most extreme onshore assembly to date has occurred at Beatrice where a jacketed foundation was assembled onshore and towed to location and sunk in place (Figures G.14 and G.15). The entire turbine and tower were assembled onshore, floated to the site, and connected to the foundation (Figures G.16 and G.17).

Seventy-five percent of the offshore turbines have been installed by the Danish company A2SEA including the turbines at Q7, Lillgrund, Nysted, Horns Rev, Egmond aan Zee, Kentish Flats, Scroby Sands, and Fredrishavn. A2SEA was formed in 2000 with the specific goal of providing construction services to the offshore wind industry. It currently operates 3 specially equipped jacking boats. While it has installed a number of turbines, it has generally not installed foundations.

In other cases, companies that do not specialize in the offshore wind power industry have been used for installation projects. For example, the North Hoyle and Beatrice projects used the companies Seacore and Scaldis, respectively. Both of these companies are marine construction companies with experience in the oil and gas and civil works industries. Seacore has also been involved in the construction of foundations, met masts and geotechnical surveys for a number of other offshore wind projects.

Larger international companies have also installed some wind farms, but their work seems to be limited to the foundations. For example, HOCHTIEF installed the foundations for the Lillgrund wind farm while Van Oord installed the foundations at Q7 and KBR installed the foundations and electrical connections at the Barrow wind farm.

7.2.6. Foundations

European developers have been cautious with the application of new technology. Despite having a number of development options, wind farms have been built in nearly identical ways. Most offshore wind projects in Europe have used either gravity foundations (Figure G.18) or monopiles (Figure G.19) as foundations. There have been a few experimental projects that have used jacketed foundations or suction caissons, though these have not been used at a commercial scale. Most projects have used monopiles and only choose gravity foundations where subsea conditions do not allow pile driving. When developers decide to test new technology, they do so at very small scales, for example, the Beatrice and Fredrickshavn projects.

7.3. U.S. Development

There are two offshore wind farms that are currently in the late planning stages in the U.S., Cape Wind and Galveston Offshore Wind. There have been several others that began planning and development at roughly the same time as these two developments, but have since been cancelled due to economic reasons. These include the Long Island Offshore Wind Park and the Padre Island Wind Park. In each case, the developer or utility decided that there were cheaper ways to generate renewable energy. Table G.4 describes the planned and cancelled developments in the U.S.

7.3.1. Cape Wind

The Cape Wind project is the best known and most controversial wind project in the U.S. Cape Wind and its opponents have been featured in national media including the CBS News, The New York Times, and NPR. Originally proposed as the nation's first offshore wind farm in 2001, its development has been delayed by opposition by local and powerful activists including Walter Cronkite, Mitt Romney and the Kennedy family.

Energy Management Incorporated (EMI), the developer of the Cape Wind project, plans to place 130 3.6 MW turbines approximately 6.5 miles off the coast of Cape Cod in an area called Horseshoe Shoal (Figure G.20). The 130 turbines will be manufactured by GE and will be arranged in a grid-like pattern. The total footprint of the site will be 25 square miles (70 km^2). The hub height will be 78.5 m which will ensure a clearance of 23m between sea level and the blades' lowest position. The turbines will be placed in shallow water, between 0.15 and 18 m deep (USDOI, MMS, 2008a).

The Cape Wind project is in the final stages of approval. Under the 2005 Energy Policy Act, the BOEMRE completed an Environmental Impact Statement (EIS) which found negligible or minimal impacts on wildlife or navigation. BOEMRE has given its regulatory approval in early 2009. According to EMI, the Cape Wind project could be operational by 2011 (EMI, 2008).

7.3.2. WEST

Wind Energy Systems Technologies (WEST) is a Louisiana based company that is planning on building a series of wind parks in state waters off the coast of Texas. Unlike most other states, Texas' state waters extend 3 marine leagues (9 nautical miles) from the shore. As a result, WEST is required to negotiate leases and permits only with the State of Texas, and is not under BOEMRE jurisdiction. Nonetheless, WEST will still have to apply for a Rivers and Harbors Act Permit.

WEST has negotiated to lease 11,000 acres of submerged land from Texas for the next 30 years. The lease is for an area approximately 7 miles off the coast of Galveston. The lease requires WEST to pay the State at least $26 million over the course of the 30 year lease. WEST has placed two meteorological observation towers on the lease. Their plan is to build a 150 MW wind farm at a cost of about $300 million (Schellstede, 2008). WEST submitted a Rivers and Harbors Act permit in late 2008. WEST has also signed leases with the state of Texas for four additional tracts off the coast of south Texas.

WEST has investigated a number of engineering concepts for building offshore wind farms in the Gulf of Mexico. They had originally planned on placing wind turbines directly on unused oil structures in the Gulf of Mexico without removing and relocating the structures; however, they seem to have abandoned this plan (Schellstede, 2004 and 2008). They then planned to use a jacked platform recycled from the oil industry as a foundation for their wind turbines and hoped that this would save the company money and make their operation profitable (Geoghegan, 2007). They have also planned to install some type of jack system which will lower the turbines in the event of a hurricane. Most recently, they have opted for installing the turbines on tripod foundations (Schellstede, 2008).

7.3.3. Bluewater Wind

Bluewater Wind is a subsidiary of Babcock and Brown. They are in the planning stages for constructing a large wind farm off the coast of Delaware. In November 2006 Delmarva Power, in response to actions by the Delaware legislature, issued a request for proposals for the construction of a new power plant in Delaware. Bluewater Wind submitted a proposal for a 450 MW wind park located 11.5 nautical miles (21 km) from the shore and was selected to negotiate a power purchase agreement in May of 2007. They estimate that it will take one to two years for construction to commence and an additional one to three years to complete construction (Bluewater Wind, 2008).

Delmarva Power has stated that they are more interested in onshore wind than offshore wind power and that they believe onshore wind power will be less expensive for Delaware consumers than offshore wind power (Benson, 2008). They also believe that onshore wind power will be ready more rapidly. Delmarva Power solicited bids from other power producers, but in the summer of 2008, Delmarva Power and Bluewater reached an agreement on the terms of a contract (Nathans, 2008) which was then accepted by the State and the project may now move forward.

7.3.4. Deepwater Wind - Plum Island Wind Park

Deepwater Wind (formerly Winergy Power LLC) was formed in 1999 by a former offshore mariculture executive. Deepwater is developing a test site off the Northern Fork of Long Island called Plum Island Wind Park. This development is meant to be a small-scale research facility; however, they are also evaluating the placement of larger projects off the east coast of the United States from Massachusetts south to Maryland.

The Plum Island Wind Park is designed to consist of three, 3.6 MW turbines or two, 5 MW turbines. The closest turbine would be 1,500 feet off of Plum Island in Gardiner's Bay and the turbines would be approximately 1,000 m from each other. At least one turbine (and perhaps two) will be installed on a monopile foundation while one other turbine will be installed on a tripod jack-up barge foundation. Deepwater intends to tow an assembled wind turbine into place on a jack up barge and leave it in place.

Deepwater has applied for a Rivers and Harbors Act permit from the Army Corps of Engineers. The public comment period closed in August 2007 and Deepwater is responding to these comments. Deepwater has also been selected as the winning bidder for projects off the coast of Rhode Island and New Jersey.

7.3.5. LIOWP

The Long Island Offshore Wind Park was a project proposed by the Long Island Power Authority (LIPA). In January 2003, LIPA issued a request for proposals to develop an offshore wind farm. FPL Energy, one of the nation's largest providers of wind and solar power, was selected. In 2007, the project was cancelled, citing economic reasons.[17] The LIOWP would have consisted of 40, 3.6 MW GE turbines with a combined capacity of 144 MW and 3.6 miles from Jones Beach on Long Island's southern side. As in the Cape Wind project, the LIOWP was opposed by some residents who feared that it would intrude on the aesthetics of the community.

7.3.6. Babcock and Brown - Padre Island Wind Farm

Babcock and Brown is an Australian investment firm with a large alternative energy portfolio. In August 2006, Babcock and Brown bought Superior Renewable Energy (SRE), a Houston based company that had planned on building a wind farm off the coast of Padre Island, Texas. SRE had leased the rights to 39,900 acres of submerged lands off the coast of Kenedy County and had planned to build a 170 turbine, 500 MW wind farm. The lease allowed for a four-year research period followed by construction and required annual payments of $80,000 plus a percentage of future earnings (Porretto, 2007). However, in June 2007, Babcock and Brown cancelled the lease saying it was "too expensive to produce energy that way in that market" implying that the price of electricity in Texas made it difficult for its project to be profitable. Babcock and Brown are currently developing onshore wind farms in Texas. The Texas General Land Office still hopes to develop the site (Porretto, 2007).

7.3.7. South Coast Wind

Patriot Renewables, LLC, has developed a plan to build an offshore wind farm in Buzzards Bay, Massachusetts. They submitted their plans to the Massachusetts Office of Environmental Affairs in May of 2006. Called South Coast Wind, their plans call for 90 to 120 turbines placed in up to three separate groups. The total capacity will be approximately 300 MW; however, the exact size turbine has not been determined. Each group will be within 3 miles of the shore in under 20 m of water. Therefore, a BOEMRE lease will not be required (Patriot Renewables, 2009).

The Secretary of the Office of Environmental Affairs of Massachusetts ruled that an Environmental Impact Report (EIR) under the Massachusetts Environmental Policy Act (similar to an EIS under NEPA) was necessary. Patriot Renewables is currently conducting the environmental analyses called for by the EIR (Patriot Renewables, 2009).

7.3.8. Proposals to BOEMRE

In November 2007, BOEMRE asked for nominations for areas to be leased for offshore wind energy, and other ocean energy development. They received over 40 nominations for resource evaluation leases. BOEMRE has decided to proceed on leasing 10 blocks, each 9 square miles for offshore wind evaluations. Five of these areas are off New Jersey, three are off the coast of Georgia and one is off the coast of Delaware. BOEMRE also received interest in wind leases off New York, South Carolina and Massachusetts, but decided not to proceed with leasing these tracts partly because the areas desired for leasing were sought by more than one developer. To

[17] LIPA commissioned a study conducted by PACE Global Energy Services to evaluate the costs of the proposed wind park. They estimated construction costs to be $4841/kW, far higher than previously anticipated or experienced (PACE, 2007).

lease under such circumstances would involve competitive leasing and would be taken up by BOEMRE only after promulgation of the regulation controlling development of offshore alternative energy projects (*Federal Register*, 2008b).

7.4. Patterns of Development

The plans for U.S. wind farms are different from the first offshore wind farms built in Europe. In the U.S., developers are not planning small 10 to 50 MW developments, but much larger projects of hundreds of MWs. There are only two small test projects under consideration. The advantage of the European pace of development was that it allowed for the development of infrastructure, institutional capacity and experience.

American projects are also not limited to shallow water close to shore, as were European projects in the early stages of development. WEST is planning on building its offshore wind farm in relatively deep water while Bluewater Wind is planning on building its Delmarva Wind Park over 20 km from the coast (Bluewater Wind, 2008).

The developers of the larger offshore wind projects in Europe are among the largest energy companies in Europe. Conversely, in the U.S., relatively small and newer companies (WEST, Deepwater Wind, and EMI), are planning on building wind farms that may cost close to $1 billion. There has been some interest among large energy companies in the U.S. in offshore wind development, most notably Southern Company and FPL Energy (USDOI, MMS, 2005a), but the most promising developments (the Galveston and Cape Wind projects) are being led by companies without the large capital and institutional experience of the larger energy conglomerates. The construction of an offshore wind farm requires a large amount of capital and would be seen by investors as a high risk investment. As a result, investors would require high interest rates. The federal government will likely require some type of surety bond to guarantee the removal of the facilities after the term of the lease. It will be far more difficult for small companies to acquire these bonds and it is likely that they will need to be heavily collateralized. Again, this will increase the costs of offshore wind farms.

American developers do not have ready access to the specialized construction equipment available to European companies, such as that developed by A2SEA and Seacore, but in the Gulf of Mexico significant expertise and construction equipment used in the offshore oil industry can be utilized. If marine construction equipment is limited, it will cause the costs of construction to increase. It is possible that global companies, for example KBR and HOCHTIEF, may also contribute to the development of wind farms in the U.S.

It is possible that the lack of companies with direct wind farm installation experience could increase the expense of development. Construction costs are sensitive to the amount of time it takes to install each turbine. In general, these construction times decline as an operator gains experience.[18] It therefore seems likely that companies with offshore wind farm installation experience would be able to complete installation more quickly than companies without experience.

[18] For example, the first foundations at North Hoyle required 132 hours to install while the last foundations took only 67 hours to install (Carter, 2007). A similar trend occurred at Horns Rev (Junginger et al., 2004).

In general, developments in the U.S. will use many of the same construction techniques that have been employed in Europe, but there are some important differences, especially in foundation types. WEST is planning on using a tripod foundation and Deepwater Wind is planning on using a three-legged self jacking foundation. Both of these are novel foundations and in both cases the companies involved plan on establishing test turbines before developing full wind farms (Schellstede, 2004 and 2008; Deepwater Wind, 2009).

Offshore wind farms are capital intensive; they can cost over $1 billion and generate little revenue for years. In Europe, large international energy companies have been the primary developers of offshore wind farms. In the U.S., this has not been the case. There are a number of advantages for large corporations over smaller start-ups in the development of offshore wind farms. Large corporations will have more available capital and will be able to raise additional capital at lower interest rates; large corporations will have less difficulty securing surety bonds and may not require decommissioning bonds; large corporations would be able to spend more time planning projects and testing new technology without the need to quickly generate revenue; and large energy companies would gain the positive environmental publicity associated with an offshore wind farm, something of less value to a company that specializes in offshore wind energy. Finally, a large company may be able to build a large number of offshore wind farms and thereby gain the institutional experience required to lower costs. A smaller company that has developed one wind farm, even a successful wind farm, would be heavily indebted and may be unable to raise the capital necessary to build additional wind farms. Thus, while small companies like WEST, and EMI may indeed build the first offshore wind farms in the U.S. and be successful, it is likely that offshore wind power will be developed at a large scale when companies like Southern Company, Babcock and Brown, and FPL Energy become committed to offshore wind energy.

7.5. Causes of Differences in European and U.S. Industries

Over the last decade, the costs of producing wind power have dropped dramatically while the costs of conventional sources of electricity, especially oil and natural gas have risen significantly (Wiser and Bolinger, 2008). This has stimulated growth in the wind industry in general in both Europe and around the world, but it has failed to stimulate the offshore industry in the U.S. This failure is due to a number of factors including different financial incentives, regulatory systems, wind resources, population densities and industry representation.

7.5.1. Financial Incentives and Subsidies

Every nation in Western Europe is an Annex 1 party to the Kyoto protocol and as such is mandated to reduce their carbon dioxide emissions. The nations of Western Europe have responded by setting mandates for the amount of electricity produced from renewable sources by specific times. In order to meet these goals, European nations have instituted a series of financial incentives (Table G.5). The primary mechanisms of financial support for renewable energy are through tax credits, feed-in tariffs, renewable energy credits, or tenders (Reiche and Bechberger, 2004).

The exact cost of a kWh of offshore wind produced electricity varies depending on the specifics of the wind farm; estimates range from 5 to 12 ¢/kWh (Fingersh et al., 2006; Dept. for BERR, 2004; Mense, 2007). Thus, a wind farm developer has to be able to reliably sell electricity for more than 5 to 10 ¢/kWh in order to make a profit. The easiest way for a developer to do so would be to negotiate a feed-in tariff, as is done in Denmark. The feed-in tariff is thought by renewable energy advocates to be the most beneficial method of renewable energy promotion, but it is not clear if this is actually the case (Reiche and Bechberger, 2004). In the case of Danish feed-in tariffs, the developer submits a bid to build an offshore wind farm at a certain feed-in price, thereby ensuring that the operation is, at least according to their plans, profitable. An alternative method for incentivizing renewable energy is through the use of a renewable energy credit market. This is the primary means of providing financial incentives in the UK. Many nations in Europe also have carbon taxes from which renewable energy generators are exempt. Finally, in the UK the government will give offshore wind developers grants to help pay for the capital costs of offshore wind farms. So far, $194 million has been divided among 10 projects (Dept. for BERR, 2008). Given that the costs of these wind farms have been in the hundreds of millions of dollars, this represents a small, but not insignificant, fraction of the total capital costs.

In the U.S., the primary federal mechanism for the stimulation of renewable energy is the Production Tax Credit (PTC). The PTC is analogous to a bonus feed-in tariff, or a carbon tax exemption. It is a 2 ¢/kWh tax credit for companies that produce electricity from certain renewable sources (including wind). It has expired three times over the last ten years; each time it has expired has been associated with a decrease in the growth of the onshore wind industry (Vann, 2007). This suggests that it is an important stimulant for the wind energy industry.

The U.S. federal government does not have a renewable energy credit trading scheme; however, twenty-five states and the District of Columbia have adopted Renewable Portfolio Standards (RPS) requiring that a certain percentage of the state's electricity be generated from renewable sources (DSIRE, 2008). RPS requirements generally range from 10 to 20 percent of production. Utilities that fail to meet these requirements must purchase tradable credits that represent an equivalent amount of renewable energy (renewable energy credits, REC) or face penalties of up to 5.5 cents per kWh.

Given that the largest penalties for non-compliance with RPS goals is 5.5 ¢/kWh, and that the federal PTC is 2 ¢/kWh, the total state and federal subsidy for offshore wind energy is at most 7.5 ¢/kWh. In most cases the actual subsidy will be much lower due to lower prices for RECs. For example, in Texas the cost of a REC in 2007 was 0.5 ¢/kWh. Even at the upper limit for RECs, the subsidies for offshore wind energy in the U.S. are significantly lower than those in Europe. For example, in the UK the tax exemptions and RECs amount to 18 ¢/kWh.

In the U.S. in 2007, the average wholesale price of electricity was about 6 ¢/kWh (Wiser and Bolinger, 2008). Including revenues from RECs and the PTC, wind farm operators may be able to sell electricity for 8 ¢/kWh. This is within the range of the costs of offshore wind power; however, the profitability of a particular farm will depend on the local energy market and capital costs of the wind farm.

In addition to being smaller, subsidies in the U.S. are less certain than those in Europe. The PTC could expire and REC prices are not set at minimum levels. Thus, unlike in Denmark where developers are guaranteed a certain price, developers in the U.S. are taking a significant risk in developing an offshore wind farm and are, in essence, gambling that REC prices increase and the PTC is renewed.

Recently, the U.S. Department of Energy (DOE) instituted a program in which it will guarantee private loans for up to 80 percent of the total project costs made to renewable energy developers (USDOE, 2008b). Guarantees may exceed $500 million, but may be made only for technologies that are not in general commercial use (are not operating in more than three facilities for more than 5 years). These loan guarantees should make financing offshore wind projects more feasible, but unlike European programs, do not provide direct grants for capital expenditures.

7.5.2. Regulations

The governments of Western Europe have instituted regulations specifically for expediting and encouraging offshore wind energy. In Denmark the government issues tenders for offshore wind farms in which developers compete to offer the government the lowest feed-in price for a given development (DEA, 2007 and 2008). This central planning has almost certainly sped development. In the UK, the Crown Estate has held two rounds of leasing which have provided an expedited system of approval. In the most recent round the government identified areas for development and conducted environmental studies before leasing (The Crown Estate, 2008). In Germany, approval of wind farms was made non-discretionary; wind farm developers have a right to build wind farms unless the government decides that they pose a threat to navigation or the environment. Furthermore, in both Germany and the Netherlands, competition is based on a first-come-first served process in which developers compete to be the first to submit an acceptable application for a given area (BSH, 2008). This could encourage speculative claims, but would also encourage developers to quickly apply for developmental rights.

The U.S. currently lacks a final regulatory system for offshore wind energy, and the development of a regulatory system has been slowed by legal challenges, Congressional action and detailed planning on the part of regulators. Therefore, despite the fact that the first offshore wind farm was proposed in U.S. waters in 2001, as of July 2008, it has not been approved. Conversely, many European wind farms have begun operation within 4 or 5 years of being proposed.

Regulations stipulate the fees that developers must pay for use of the seabed. The fees that European nations charge for use of the seabed are either minimal or nonexistent and they are almost never competitively determined (DEA, 2007 and 2008; The Crown Estate, 2008; BSH, 2008). The proposed U.S. regulations include modest royalties for use of public lands that are based, in part, on competitive bidding for the proposal with the largest monetary benefit to the state (Table G.6). The presence of these fees will have an effect on the profitability of wind farms in the U.S.; however, their impact will be dwarfed when compared to the differences in subsidies offered in Europe and the U.S.

Some other differences in regulatory structure that may impact development are given in Table G.6. It is possible that the long leases of the UK system or the site selection by regulators in the

UK and Denmark could have sped development in these countries (Concerted Action for Offshore Wind Energy Deployment, 2005).

7.5.3. Wind Resources

One of the most critical reasons for the development of the offshore wind industry in Europe is the larger number of suitable sites. In general, wind speeds increase further from shore. This increases the electrical production of turbines, but the additional distance also increases their cost. The challenge for developers is to find sites that have high winds but are close to land and in shallow water. There are a number of sites off the coast of northern Europe where wind speeds average 9 to 10 m/s at 50 m (Figures G.21 and G.22). These wind speeds are considered superb by NREL for wind energy production. In contrast, the winds off the coast of New England are generally 8 to 9 m/s while those in the Gulf of Mexico are 7 to 9 m/s. The Pacific coast does have areas of 9 to 10 m/s winds, but these are generally in deepwater. There are small areas of high winds and shallow waters off the coast of New England (Figure G.23). These sites are likely as suitable as those in Europe. Even the more modest winds of the Gulf of Mexico can be developed; however, they are likely to have lower capacity factors and therefore lower revenues.

7.5.4. Population Density

Population density is an overlooked driver of offshore wind development. Due to the high population density of Europe, Europe has less room to expand onshore wind energy production (Ackermann and Söder, 2002). Much of Europe is densely populated, including Denmark, the UK and Germany, the countries that have seen the most offshore wind development (Figure G.24). This high population density effectively forecloses increased onshore wind development, often the cheapest renewable energy source.

Conversely, the wind resources of the U.S. are concentrated in the Midwest where population densities are low, thus there is ample room for expansion of onshore wind resources without significant conflicts with local populations (Figures G.23 and G.25). U.S. developers interested in wind development can therefore develop cheaper and less risky projects onshore without the need to go offshore.

In general, the populations of both the U.S. and Western Europe have similar attitudes towards local offshore development. As in the U.S., local residents in Europe are willing to pay to keep wind farms out of their viewshed. In the U.S., Haughton et al. (2003) estimated the willingness of Cape Cod residents to pay for not placing wind farms in their area to be $75 per person, while Ladenburg and Dubgaard (2007) estimated a similar value at approximately 120 Euros ($190) for Danes.[19] Although the results are not directly comparable, they do suggest that in both places citizens place a modest premium on viewsheds unobstructed by wind turbines.

[19] In the Danish case the willingness-to-pay was estimated on a per household annual basis, while in the U.S. study, payments were assumed to be one time and per person.

7.5.5. Commercial Interests

Europe is home to some of the largest producers of wind turbines including Siemens, Enercon, Gamesa, Vestas and Repower (Table G.7). Similarly, Europe is the primary source for submarine transmission cables used in offshore wind farms (Wright et al., 2002) and has a well-developed offshore construction industry associated with the North Sea oil and gas industry. As a result, each offshore wind development has a cascading impact on jobs throughout the European economy providing jobs in the offshore construction, turbine, and cable industries, as well as the companies that support those industries, especially banks and steel manufacturers.

European legislators, especially in Denmark and Germany, have an incentive to aid in the development of markets for wind turbines and European companies can put pressure on legislators to encourage wind farm development. Conversely, in the U.S. offshore turbines may or may not be made in the U.S. and the marine cable almost certainly will not be. (Wright et al., 2002). Thus, the number of jobs created per MW of offshore wind capacity will be lower in the U.S. than in Europe. Furthermore, the major U.S. wind turbine manufacturer, GE, is not primarily a wind turbine company (unlike Vestas or Enercon) and GE profits, and thus its lobbying effort, will only be marginally impacted by an offshore wind industry.

7.6. Potential Policies for Increasing Offshore Wind in the U.S.

There are a number of policies which could be adopted by the U.S. that could stimulate the offshore wind industry (Bird et al., 2005). It is unlikely the U.S. will mimic successful European policies like feed-in tariffs; it is more likely to implement market driven policies (Birgisson and Petersen, 2006) and policies similar to those it already has some experience with. Here, we discuss the potential impacts of four policies on offshore wind energy. We discuss the effects of a federal renewable portfolio standard, an extension of the production tax credit, and the adoption of a cap and trade program. All of these continue to be debated by Congress, and a cap and trade program is believed to be most cost-effective (Palmer and Burtraw, 2005). We also discuss the creation of national offshore-wind capacity goals, something that is common in Europe. There are other state-level methods of alternative energy promotion, but these are thought to be less effective (Birgisson and Petersen, 2006; Menz and Vachon, 2006). We do not intend this discussion to offer support or condemnation of these policies, only to discuss their likely impacts on offshore wind development.

7.6.1. The Production Tax Credit

The PTC is similar to the tax credits in some European countries and is similar to a feed-in tariff (Toke, 2007). However, in European nations, the tax credits are generally exemptions from carbon taxes, which do not exist in the U.S. Among the most likely ways for the federal government to stimulate offshore wind energy would be through an extension or expansion of the PTC. The PTC is a reasonable stimulant for the onshore wind industry, but due to the long planning needed for offshore wind projects it is a poor stimulant for offshore wind energy (Wiser et al., 2007).

The PTC has expired 3 times in the past decade and extensions of the PTC have been for only one or two years at a time. Most recently, the PTC was extended by the Senate until January, 2010. However, this short extension is not long enough to allow for the long-term planning required by offshore wind farms. A project in the planning stages in 2008 would not be operational until well after 2010, when the PTC would again expire. In order to be useful for offshore wind farms, a PTC commitment of at least a decade is needed.

Additionally, unlike tax credits in Europe, the PTC is designed to apply only for the first ten years of operation. However, the cost of energy is unlikely to decline for already established offshore wind projects over time. Thus, a company may be able to profitably produce electricity for the first 10 years of operation, but be unable to cover its operating expenses after it is no longer covered by the PTC.

Critics of the PTC argue that it was originally designed to provide an incentive to the developing renewable energy industry and it should now be allowed to expire (Vann, 2007). However, unlike European feed-in policies, the PTC treats all renewable energy technologies equally. Thus, while onshore wind is now profitable and likely does not need the PTC in order to compete with coal and natural gas fired power, offshore wind power is a newly developing industry and cannot compete on price with conventional electricity. Thus, the PTC could reasonably be extended for 10 years for new offshore wind projects without defying its original purpose.

In addition to extending the PTC, Congress could increase it. Again this could be done either for alternative energy in general, or some subset of technologies. In the case of offshore wind energy, the cost of production varies dramatically depending on site specific factors, but it is likely to average about 10 to 12 cents per kWh in the U.S. (Fingersh et al., 2006; Dept. for BERR, 2004; Mense, 2007). The wholesale price of electricity in 2007 at the NEPOOL hub in New England was 7.7 cents per kWh. This is the hub most likely to be impacted by offshore wind energy. If the PTC is meant to be a subsidy to encourage renewable energy development and to make it at least temporarily competitive with conventional electricity, then the PTC might need to be set to approximately 3 ¢/kWh in order to make it competitive with more traditional power sources.

Each 1,000 MW of offshore wind capacity would cost the government 61 million dollars per year (with a 2 ¢/kWh PTC, $92 million with a 3 ¢/kWh PTC; assuming 35 percent capacity factor). If Congress were to extend the PTC for offshore wind for 10 years, it seems probable that no more than 2,500 to 5,000 MW of capacity could be built. This would suggest a maximum subsidy by the federal government of $152 to $305 million per year with a 2 ¢/kWh PTC.

7.6.2. Greenhouse Gas Legislation

The Lieberman-Warner bill was voted out of committee for consideration by the full Senate in December 2007 but failed to pass the Senate in June of 2008. It called for the establishment of a cap and trade program which would cap greenhouse gas emissions but would allow emitters to purchase offsets to satisfy up to 15 percent of their obligation. It would establish a national mandatory carbon market which would replace or supplement the voluntary market already in place. In the REC market the price of credits in compliance markets is often higher than the price of credits in the voluntary market.[20] It seems likely that the imposition of a cap and trade program would therefore boost the price of carbon credits which would increase the costs of conventional electricity and increase the profitability of any renewable energy project. The Lieberman-Warner bill failed to pass in the 110th Congress.

Carbon taxes have also been suggested as a means for combating climate change and are used in Europe. In the 110th Congress, two bills were introduced into the House of Representatives that proposed carbon taxes of $2.7 or $15 per metric tone of CO_2 with incremental increases. A carbon tax would function to make non-renewable energy more expensive, thereby giving offshore wind power a competitive advantage. In the U.S. on average, there is 0.839 metric tones of CO_2 emitted per MWh (Sims et al., 2003). Thus, a $10 per metric tone CO_2 tax would, on average, increase electricity prices by 0.839 ¢/kWh. This is not enough to have an appreciable effect on the profitability of offshore wind power. Carbon taxes also do not seem to be as popular with lawmakers as are cap-and-trade programs.

7.6.3. Renewable Portfolio Standards

Twenty-five states and the District of Columbia have RPSs (DSIRE, 2008). This includes almost all of the states in which offshore wind is a realistic possibility (excepting Louisiana and Georgia). The U.S. Congress has considered the establishment of a national RPS (Nogee et al., 2007). In 2007 the House and Senate debated bills that would set an RPS target of 15 percent renewable energy by 2020. The Senate has passed similar bills three times. The most recent bills also contained annually increasing goals between 2010 and 2020 and included trading schemes, penalties and caps for the prices of RECs. Opponents of the federal RPS argued that the system would be unfair to the South and Midwest regions of the U.S. because of the unequal distribution of renewable energy potential and that it would cost consumers billions of dollars.

The combination of the federal PTC and state RPS has stimulated wind energy development (USDOE, EIA, 2006) with modest impacts on electricity prices.[21] It is reasonable to expect that a federal RPS would similarly stimulate the offshore wind industry (Short et al., 2004). However, there are also reasons to doubt the efficacy of a federal RPS program for offshore wind. While federal legislation will only set a minimum RPS which states may exceed, most of the coastal states already exceed the proposed federal RPS. Thus, the only way that a federal RPS would be beneficial for offshore wind would be if it caused the prices of all RECs to increase. This may occur since a federal RPS would increase demand for RECs.

Interestingly, if, following the passage of a federal RPS, a state allowed an electricity producer to purchase RECs to meet the federal RPS from outside the state, this might actually lower the price of RECs. For example, utilities in Massachusetts are required to supply 15 percent of their electricity from renewable sources by 2020, but they currently must purchase expensive Massachusetts RECs to offset gaps in production. If federal legislation passed, Massachusetts

[20] Similarly, as of March 2008 the price of carbon credits on the European Climate Exchange (a mandatory EU market) was seven times higher than the price of credits on the Chicago Climate Exchange (a voluntary market; see www.chicagoclimatex.com and www.europeanclimateexchange.com).

[21] Increase in prices may be less than 1 percent (Chen et al., 2009; Wiser et al., 2007).

electricity retailers could purchase RECs on a national market. While this new national market would have stronger demand than a regional market, its supply would also be much different. In a state market like that in Massachusetts, the production costs of RECs can be quite high because of limited renewable energy potentials. On a national market, RECs are likely to be dominated by onshore wind production which is already profitable without RECs and the supply of which would vastly outweigh RECs from offshore wind power. As a result, this could depress the price of RECs in many markets.

7.6.4. National Goals for Offshore Wind Power

Governments in Europe have frequently used national goals as instruments of policy. For example, Denmark set a goal of producing 15 percent of its energy from wind power by 2005. It has been argued that the establishment of this goal sent a signal to the wind industry that the national government was serious about the future of wind power and Denmark met this goal 3 years early (Peloso, 2006). Similarly, the Dutch have set a goal of 6,000 MW of offshore capacity by 2020 (Mast et al., 2007). Goals can be purely aspirational, or they could be mandatory, as in state RPS standards. A national goal for offshore wind power in the U.S. could occur in the context of a larger goal for wind power or ocean energy in general.

In May 2008, the U.S. Department of Energy released a report entitled "20 % Wind Energy by 2030." The report does not specifically advocate for generating 20 percent of U.S. electricity consumption with wind power by 2030, instead it is meant to discuss the feasibility of such a goal. The report concludes that this goal is ambitious but feasible and that it would have numerous benefits. The DOE report assumes that offshore wind power capacity is about 50 GW in 2030, about 15 percent of overall 2030 wind capacity.

A relatively modest but achievable goal might be to have 5 GW of capacity (roughly 10 to 12 Cape Wind sized developments) by 2020. Total nameplate U.S. electrical capacity in 2006 was 1,075 GW, so this commitment would only account for one-half of one percent of capacity. The goal described in the 2008 DOE report of 50 GW by 2030 would require at least 100 Cape Wind sized projects. Given the limited shallow-water offshore wind resources of the U.S., this goal would be difficult to achieve without deep-water technology.

The effects of a goal would differ markedly depending on if the goal were part of a national technology specific RPS program (and thus a mandate) or an aspirational goal. Several states specify the proportions of certain technologies that must be used to meet RPS standards. The federal government could follow this example; however, this seems unlikely. A voluntary goal would not change the underlying economics of offshore wind and it therefore seems unlikely that it would have significant impacts on the development of the industry.

7.7. Conclusions

The development of the offshore wind industry in Europe has been largely driven by government policies and financial incentives. The types and scale of financial incentives used in Europe seem unlikely in the U.S. since the U.S. has no international obligation to limit carbon emissions and generally seems to prefer "market-driven" solutions like cap-and-trade or renewable energy credit programs over either carbon taxes or feed-in prices. This, combined with the fact that Northern Europe has several sites that are well suited for offshore wind with currently available technology, makes it unsurprising that the offshore wind industry has developed outside the U.S. It is important to note that the U.S. does have sites that are amenable to offshore wind energy, but that if policymakers hope to see offshore wind development in the U.S. commensurate with that of Europe, they will have to increase subsidies.

From the perspective of offshore wind development, the most useful policy change would be a modest increase in the size and duration of the PTC. A 10 year commitment is necessary in order for new offshore developments to be able to have confidence that it will be available. While the lack of regulation has stalled development in the past, this problem is being corrected, and it seems unlikely that the leasing system and fees under development by the BOEMRE will forestall development in the future.

The ambitious plans of small start-up companies might concern some stakeholders interested in the development of a viable offshore wind industry since they are quite different from the development of the European industry. It is not clear that all of the developers interested in offshore wind in the U.S. have the requisite infrastructure and institutional capacity to develop a new commercial offshore industry. However, if these companies can finance their projects and use the marine construction experience of the offshore oil and gas industry or other marine construction industries, then they may be able to rapidly develop a commercial offshore wind industry and skip over the long slow period of experimental development that occurred in Europe.

Onshore wind development is experiencing rapid growth in the U.S. and is the second largest source of new capacity additions behind natural gas (Wiser and Bolinger, 2008). If this growth continues, at some point onshore resources will no longer be readily available, increasing the costs of onshore wind due to the costs of leasing land, and making offshore wind more attractive. In 2007, over 5,000 MW of new capacity was added. Assuming a turbine density of 5 MW per km^2, then over 1,000 km^2 were converted to wind farms in 2007 (USDOE, 2008a). Presumably, the sites with the highest wind speeds and lowest land lease or purchase costs are developed first. When these sites are no longer readily available, offshore development may expand.

Even if the first offshore wind developments in the U.S. are successful and the profitability of offshore wind farms in the U.S. is increased through increased government subsidies, the different wind conditions and population densities in Europe and the U.S. will ensure that offshore wind is more common in Europe than the U.S. The fact that onshore wind resource sites are still widely available in the U.S. and that the onshore environment is inherently less costly and risky will cause offshore wind to be at best a small contributor to electricity production in the U.S. for the foreseeable future.

8. ECOLOGICAL AND ECONOMIC COST-BENEFIT ANALYSIS OF OFFSHORE WIND ENERGY

In this chapter, we seek to address the question, "Is investment in offshore wind power preferred over investments in fossil fueled or onshore wind power." We focus primarily on coal fired power as representative of fossil fueled power since it is the dominant source of electricity in the U.S. and it is both inexpensive and a major source of greenhouse gases.

We begin with an overview of the commonly expressed criticisms and benefits of offshore wind power. We discuss cost models for offshore wind power and compare to onshore wind power and conventional power. We also discuss the factors that lead to higher costs through a first-order empirical cost function and discuss how costs can be reduced. We discuss the environmental impacts of offshore wind power and how these factors can be mitigated. We end the chapter with the conclusions of the analysis.

8.1. Introduction

Over the past 10 years, the onshore wind industry in the U.S. has grown dramatically and as a result developers, citizens and the U.S. Congress have expressed interest in the development of an offshore wind industry. Several companies have developed plans for offshore wind projects and the BOEMRE is in the process of reviewing these applications and developing regulations for the industry while the state of Texas has already leased lands for at least one and possibly several additional offshore wind farms. Lawmakers, government agencies, corporations, non-governmental organizations and private individuals are deciding whether or not to support or participate in the development of an offshore wind industry, and the relative level of support or encouragement to give. In making these decisions, stakeholders will have to balance the ecological costs and benefits of offshore wind against its economic costs and compare to offshore wind energy's most realistic competitors. The decision is complex and requires balancing local and global environmental issues, historical conservation and economic costs.

Given the uncertainties associated with global climate change, it is difficult to compare the societal costs and benefits of wind energy to fossil fueled energy. However, one way to develop a first order comparison of these costs would be to include the costs of market based carbon offsets in the costs of conventional electricity. This assumes that the costs of carbon emission credits accurately reflect their ecological value which would occur if carbon credits actually represent a reduction of the specified amount of carbon dioxide from the atmosphere.

8.2. Criticisms of Offshore Wind Power

There have been a number of criticisms of offshore wind power in the U.S., mostly associated with the Cape Wind project (Table H.1) (Firestone and Kempton, 2007; Firestone et al., 2007). The environmental impacts are discussed in more detail below, the rest of the concerns are discussed here.

8.2.1. Navigational Safety

Any structure placed in federal water must receive a permit from the Army Corps of Engineers (COE). The COE, through the Rivers and Harbors Act (RHA), has the authority to regulate obstructions to navigation in federal waters. The COE considers a multitude of factors in making RHA decisions; however, their primary responsibility is protecting navigation. Therefore, they are unlikely to permit offshore wind projects that pose serious threat to U.S. shipping lanes. However, densely spaced wind turbines could provide a problem for recreational boats and small fishing vessels attempting to navigate through a wind farm, and for commercial vessels passing nearby. The amount of acreage covered in wind farms for a 400-600 MW site will likely range between 25-40 square miles. Typically, turbines in a wind farm are spaced 500 to 1,000 m apart and have blades that at their lowest point are at least 20m above the water. Small boats should therefore have no problem navigating among these turbines in good weather; however, critics of the Cape Wind project, including the Alliance to Protect Nantucket Sound, have pointed out that the coast of Massachusetts is infamous for bad weather and shipwrecks. This is likely to be the case in many places in which offshore turbines are particularly profitable (i.e. areas with high winds).

8.2.2. Federal Subsidies

Opponents of offshore wind projects claim that offshore wind power is not economically viable without federal "subsidies", by which they mean federal tax credits for renewable energy. The federal Production Tax Credit (PTC) gives a tax credit of 2 cents per kWh of produced electricity for the first ten years of production from any renewable source, including wind.[22] Opponents of the PTC argue that its original purpose was to help the renewable energy industry become established and because it originally became law in 1992, it should now be allowed to expire. In fact, the PTC did expire in 2000, 2002 and 2004 and is currently set to expire at the end of 2008. Interestingly, the pattern of wind capacity growth in the U.S. seems to closely follow the expiration of the PTC (Bird et al., 2005). In each of the years in which the PTC was allowed to expire, the growth in wind capacity slowed markedly. Given the relatively unfavorable economics of offshore wind, it is reasonable to suggest that offshore wind energy projects will need the continuation of the Production Tax Credit (PTC) in order to be competitive.

8.2.3. Aesthetics

Opponents to wind power claim that wind turbines mar the landscape or seascape. This is especially an issue for the Cape Wind project in which local activists are concerned about the views from historic landmarks. There are some aesthetic issues that are beyond the scope of analytic tools, however, the effects of wind farms on property values has been analyzed. Sterzinger et al. (2003) analyzed property values in the viewshed of onshore wind turbines and found that in eight out of ten cases the property values in the viewshed increased faster than the values in control sites. Furthermore, in nine of ten cases the rate of property value increase rose

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[22] For example, if a 400 MW wind farm has a capacity factor of 50 percent, then it would produce about 1.7 billion kWh of electricity annually, and would qualify for 35 million dollars in tax credits each year for the first ten years of its operational life.

after the placement of the wind farm. Thus, there is no empirical evidence to suggest that wind farms negatively influence property values.

In Denmark, Ladenburg and Dubgaard (2007) estimated the willingness of citizens to pay for moving turbines further from shore. They found that respondents were willing to pay 46, 96 and 122 Euros per year per household in order to move a theoretical wind farm to 12, 18 or 50 km away from the coast, relative to a 8 km baseline (Ladenburg and Dubgaard, 2007). Haughton et al., (2003) conducted a similar study on Cape Cod and found that 22 percent of respondents were willing to pay, on average, a one time cost of $286 dollars for windmills to not be built, while 9 percent were willing to pay an average of $112 for windmills to be built. The average net willingness to pay per person was $75. These data suggest that on average the public views offshore wind turbines as visual disamentities, at least before they are built.

8.2.4. Cost and Risk

The offshore environment is significantly more uncertain and difficult than onshore, and thus, more costly and risky. The offshore environment involves personnel traveling to and from offshore turbines; this increases costs as well as insurance due to increased risks. Offshore work involves increased risks of storms which affect the amount of time available for maintenance and installation which in turn influence capital and operation costs. Offshore environments are corrosive to electrical and structural equipment and require turbines to be marinized with cathodic and humidity protection. Capital expenditures for offshore wind projects depend on marine vessel dayrates which are unpredictable, and offshore foundations require more steel for jackets and pilings than onshore foundations.

8.2.5. Unpredictable Power

One of the most substantive criticisms of wind power is that it is unable to provide constant, predictable power to the grid. The electricity grid is designed to send a constant AC load to consumers and it relies on large power plants producing predictable and steady electricity. Wind energy is not steady and varies on the scale of minutes, hours, days and months and the changes in wind power output are difficult to predict ahead of time (Hirst and Hild, 2004). Therefore, integrating wind power into the electricity grid will require backup systems (especially natural gas fired power plants) that can respond quickly to changing production from wind farms (Lund, 2005). This increases the total national cost of electricity. The DOE has estimated that the cost to supply up to 20 percent of the nation's electrical use from wind power would cost up to $5 per MWh in integration costs (USDOE, 2008a).

8.3. Benefits of Offshore Wind Power

Offshore wind power shares all of the same benefits of onshore wind power relative to conventional power sources (Table H.1). Most notably, wind power has very low carbon emissions over its lifecycle, as well as negligible emissions of mercury, nitrous oxides and sulfur oxides. Wind power does not use fuel and is therefore freed from the price volatility associated with electricity generated from oil, natural gas, biomass, nuclear and coal. Wind power does not rely on large sources of freshwater as conventional sources of power do (USDOE, 2008a). In the near term, offshore wind power will be more expensive than onshore wind power; however, there are several benefits of offshore wind power that are not shared by onshore wind; these benefits may or may not justify the additional costs.

8.3.1. Location

Onshore wind resources in the U.S. are localized in the middle of the country, far away from large population centers. Offshore wind power is physically close to the major population centers of the coastal United States, thereby removing the need for expensive high voltage transmission (USDOE, NREL, 2008). However, with a large enough investment, it may be more efficient to build these transmission lines than it would be to invest in offshore wind power. Recent studies have evaluated the costs of producing 20 percent of the nation's electricity from wind (primarily onshore wind). The cost to transmit this electricity from the wind centers of the west and Midwest to the population centers on the coasts has been estimated to be about $20 to $26 billion. This would add about $120 to $180 to the capital costs of new construction making total capital costs about $2000/kWh, below current offshore costs of around 3000 to 4000 $/kWh (USDOE, 2008a).

Onshore wind power has, in some cases, been stalled by local opposition due to conflicts between alternative land uses (Righter, 2002). One potential benefit of offshore wind is that it may reduce this conflict (Pasqualetti, 2004). Wind turbines can be placed far enough from the shore to be inaudible and, potentially, invisible. Local opposition to the Cape Wind project remains strong, but does not seem to be the case in the Galveston Offshore Wind Project (Patterson, 2005).

8.3.2. Power

Offshore winds are generally stronger and more constant than onshore winds. As a result, turbines are expected to operate at their maximum capacity for a larger percentage of the time, and the constancy of wind speed reduces wear on the turbine and provides a more constant source of power to the electrical grid reducing the need for other sources of electricity to serve as backups (IEA, 2005a). The increase in wind speed has been reported to lead to a 150 percent increase in electricity production for offshore wind turbines (Vattenfall, 2008) and an increase in the capacity factor of the wind farm from about 25 to 40 percent (Junginger et al., 2004).

8.3.3. Transport and Construction

The marine cranes developed for the offshore oil and natural gas industry are capable of handling larger equipment than onshore cranes, thus allowing for larger turbines to be efficiently erected at sea. The transportation of the required enormous pieces of equipment is also made significantly easier at sea (Musial and Butterfield, 2004). The size of onshore turbines is limited by the ability to transport the blades, tower and nacelles (the section of the turbine to which the blades are attached and that houses the mechanical and electrical equipment) of the turbines. As a result, cost reductions due to the economics of scale are limited. However, at sea these constraints are not an issue and wind turbines already exceed 5 MW and will likely eventually exceed 10 MW. These larger turbines may make offshore wind power more economically attractive due to the economies of scale.

8.3.4. Design Considerations

Offshore wind power also has several potential benefits that have not yet been realized due to its nascent nature; these benefits are related to the potential for new turbine designs optimized for the offshore environment (Lemming et al., 2007).

Turbine noise is an oft-cited criticism made by opponents to onshore wind power (Pedersen and Waye, 2004). The offshore wind power industry does not have to be as concerned about turbine noise as does the onshore industry. As a result, the offshore industry can use far larger turbines (Musial and Butterfield, 2004). These larger turbines should make offshore wind power more economically attractive due to scale economies. Additionally, if offshore turbines are freed from constraints of noise, then turbine manufacturers could build turbines with downwind rotors, that is, rotors that are located behind (with respect to the wind direction) the support tower and nacelle. In upwind rotors, extreme wind speeds could deflect the blades back towards the tower. Thus the blades have to be made very stiff, increasing their price and weight (the increased weight also increases the expense of the tower, foundation and construction). In a downwind rotor the blade can be more flexible. However, as the blades pass through the wind shadow caused by the tower they create a low frequency noise. Offshore wind farms would not need to be as concerned with this noise (Butterfield et al., 2007).

Offshore wind farms located over the horizon could also make use of lattice towers instead of tubular towers. These lattice towers require less material and are therefore lighter and cheaper than the more common tubular towers; however, they are rare for aesthetic reasons (Gipe, 2004). Similarly, two bladed turbines were rejected by the European market for aesthetic reasons (Butterfield et al., 2007); however they are lighter (and therefore less expensive) than three bladed turbines.

8.4. Cost Estimates of Wind Power

The economic costs of conventional, onshore and offshore wind power are shown in Table H.2. The estimate for conventional power comes from an average of all power generation in the U.S. There is a great deal of variation in the estimates for offshore wind costs which is due to the assumptions of the analysts and the year in which the estimates were performed. Commodity prices have increased significantly in recent years, and the costs of turbine construction and installation have also increased, both onshore and offshore. Additionally, the methodology through which cost estimates are made, and their potential application can differ significantly. What is clear is that the costs of onshore wind power are competitive with conventional power sources, but that the costs of offshore wind power are more expensive than either onshore or conventional electricity perhaps by a factor of 2 to 3. The exact price of the premium is time and site specific, but may be up to $50/MWh. Since onshore wind is cost competitive with conventional electricity, the premium is similar for both energy sources and may be higher for onshore wind than for conventional power.

8.4.1. Costs of Onshore Wind Power

Data on the costs of offshore wind power is relatively sparse due to the limited number of installations and the lack of reporting. Data on onshore wind power costs are more readily available. The price of onshore wind generated electricity (cost of energy; CE) declined from 1999 to 2005 from approximately $63/MWh in 1999 to $36/MWh in 2005 (Wiser and Bolinger, 2008). However, in 2006 the price began to rise again and in 2007 the price of wind generated electricity was $40 per MWh (all prices in 2007 dollars). Even with this increasing price, wind power is competitive with conventional power sources; since 2003 wind generated electricity has been at or below the average national wholesale price of power.

Part of this rising price is attributed to the rising capital costs of wind farms. From the early 1980's to the early 2000s, capital costs of wind farms declined by $2,700/kW (Wiser and Bolinger, 2008). From 2001 to 2003 the capital costs for onshore wind farms averaged about $1,450/kW; by 2007 these costs had risen to $1,710/kW. These increasing project costs are due to increasing turbine costs which have increased as demand and commodity prices have grown.

The primary drivers of the CE are the capital costs of a wind farm and the capacity factor. CE increases with the capital costs and decreases with the capacity factor (Wiser and Bolinger, 2008).

8.4.2. Offshore Cost Estimates

Musial and Butterfield (2004) developed a model of the costs of offshore wind farms. They modeled a hypothetical 500 MW wind farm composed of 100, 5 MW turbines. The farm was in shallow water, 15 miles from the coast. They assumed that the turbines would cost $340 million, the foundations $100 million and the electrical connections $160 million. This gave a total construction cost of $1,200/kW and a cost of energy of $54/MWh.

Fingersh et al. (2006) modeled the costs of a single 3 MW turbine in shallow water, but included the per turbine costs of electrical interconnection. The cost of electricity was a function of the annual expenses divided by the annual energy production. The annual expenses included the rate of return on the initial capital investment (11.85 percent) times the initial capital required ($6.3 million; $2,100 per kW) plus the land lease costs ($12,000), operation and maintenance costs ($215,000 per year), and replacement and overhaul costs ($55,000 per year). Fingersh et al. (2006) assumed a capacity of 38 percent and predicted the total costs to be $95/MWh. They used a similar method to estimate the costs of onshore wind power and found them to be roughly half the costs of offshore wind power.

In the now defunct Long Island Offshore Wind Park (LIOWP) agreement between FPL Energy and the Long Island Power Authority (LIPA), LIPA agreed to pay $94.97/MWh for offshore produced wind power. This rate was designed to increase annually at 2.75 percent (Greer, 2007). PACE Global Energy Services conducted an independent report for LIPA and found that the costs of construction were approximately $750 million ($5231/kW). This translated into a cost of energy of $291/MWh (PACE, 2007). PACE also estimated the costs of a future (2010) generic European offshore wind farm at $4,000/kW. This high cost is due to the increasing price of materials (PACE, 2007).

8.4.3. Cost Components

The primary component costs for on and offshore wind based on empirical studies are shown in Figure H.1. The primary capital cost for onshore wind projects is the turbine; installation costs make up about 14 percent of the total capital costs. For offshore wind projects, the costs of installation is higher, approximately 20 percent of the total costs and the costs of building and installing the foundations account for another 20 percent of capital costs. For offshore wind, operation and maintenance costs make up a larger proportion of the overall components of the CE (Fingersh et al., 2006). This is likely due to the costs of accessing offshore wind farms and maintaining turbines in operating condition.

8.5. Offshore Cost Functions

8.5.1. Data Source

We have compiled data from a variety of public sources on the costs of offshore wind farms built in Europe (Table H.3). Construction costs have ranged in price from $1,462 to $7,000 per kW of capacity and average $3,354 per kW of capacity. Excluding Beatrice, estimated costs for not yet completed wind farms and developments built before 2000, construction costs for wind farms built between 2001 and 2007 ranged from $1,462 to $3,125 per kW. We believe the smaller sample is more representative of general trends and use it in further analyses.

These data come from a variety of sources including developer websites which we cannot independently verify. These data may not reflect the entire costs of construction in all cases such as the cost of transmission studies and permitting. The cost data were inflated to 2008 dollars by converting the original cost to dollars using the average exchange rate in the year in which the estimate was given (assumed to be the year of construction unless otherwise indicated), then inflating to 2008 dollars using the U.S. Bureau of Labor Statistics calculator.

8.5.2. Model Specification

We created multiple regression models of capital cost based on several factors. We hypothesized a cost model in which the predictor variables were total capacity, water depth, distance to shore, year constructed, turbine size, and number of turbines. We had no reason to assume that any interaction or higher-order terms would be appropriate, and the cost models should be viewed as a first-order approximation in a complex environment.

Total Capacity

Obviously, increasing the size of development will increase the capital costs of a project and this parameter is needed in order to control for varying sizes of developments. However, the costs are unlikely to scale linearly with the size of development. Installation costs, and grid connection costs, and even turbine costs are unlikely to scale linearly with the size of the wind farm. For example, for orders of over 100 turbines manufacturers typically provide for a 20-30 percent reduction in the list price (Junginger et al., 2005). Nonetheless, we expect that the total capital costs will increase with increases in total capacity.

Turbine Capacity

There is a clear trend toward increasing turbine size in onshore (Wiser and Bolinger, 2008) and offshore applications. This could decrease costs since larger capacity turbines would require fewer foundations for the same sized wind farm. However, larger components require larger barges and cranes for construction which are less common and more expensive than smaller barges. There is no relationship between turbine capacity and the per kWh capital costs of offshore wind farms (Figure H.2) and so we do not hypothesize a relationship between increasing turbine capacity and capital costs.

Distance to Shore

The distance to shore influences both the construction and operation and maintenance costs. During construction the ships will have to make a number of trips between the site and shore to load equipment. This travel period is costly and therefore the closer a offshore site is to an industrial port facility, the less expensive installation will be. Furthermore, the distance to shore also dictates the amount of transmission cabling required. During operation a maintenance crew will need to make regular trips to the wind farm to monitor the foundations, towers and turbines (Larsen et al., 2005). Locating this crew as close as possible to the wind farm will decrease both the environmental impacts and the costs of maintenance. We expect distance to shore to be positively related to capital costs.

Water Depth

Water depth is a primary factor in most offshore operations in the oil and gas industry, and thus we suspect water depth will also play an important role in determining costs in offshore wind development. Increasing depths increase the price of construction by making monopile and gravity foundations impractical and potentially requiring the use of expensive, jacketed foundations and expensive marine vessels for installation (Butterfield et al., 2007). Shallow water can restrict the access of some large barges which could also restrict operations. Many cable laying vessels have deep drafts (up to 8 m); therefore shallow water may necessitate the use of remotely operated vehicles (ROVs) for cable laying operations. Use of ROVs and divers in offshore construction will significantly impact costs.

Year of Construction

There is a general expectation that technological learning will cause the cost of offshore wind installations to decrease (Junginger et al., 2004). This has occurred in the onshore wind industry with consequent expansion in capacity, and there is a great deal of expectation that a similar phenomenon will occur in the offshore wind industry. Year of construction may be negatively associated with capital costs, but we do not suspect the sample set is sufficiently large to detect such effects.

8.5.3. Model Results

We checked the variables for colinearity using a correlation matrix and found no parameters with correlation coefficients greater than 0.7. Therefore, we left all parameters in the model and applied various combinations of the parameters and ranked the models according to their adjusted R^2 value. The models and their parameter estimates are given in Table H.4. While the adjusted R-squared of model one is the highest (indicating it explains the most variance) model 2 may be the most parsimonious model.

Three variables common to all three of the best models were total capacity, distance to shore, and turbine size. As expected, costs increased with increases in total capacity and distance to shore, and decreased with increases in turbine size. This suggests that as turbines increase in size the total costs of offshore wind power will decline. The year of construction and water depth were not significant in any of the models. The water depths in the sample set ranged from 1 to 21 meters which is not sufficient to detect depth effects. The cost element is also too gross to expect time to play a significant role in the model.

8.5.4. Limitations of Analysis

The capital costs of offshore wind farms is governed by conditions unique to the structure, site, contractor, and country as well as the prevailing environmental, engineering, market, operational, and regulatory conditions at the time of the operation. The unique nature of offshore operations and construction objectives drives the variability observed and can only be partially explained through factor analysis.

8.6. Managing Costs

With a CE of up to $100 per MWh, offshore wind is not currently cost competitive with either onshore wind or conventional electricity. However there are a number of factors which may lead to significant cost reductions in the future and there are many factors that may make offshore wind locally attractive. The CE for offshore wind power is determined by the capital costs of installation, the interest rate, the operation and maintenance costs, the energy produced, and the sales price of electricity. These factors are in turn determined by a variety of other factors. Offshore wind developers have little control over some of these factors (e.g., the interest rate), but site selection and project planning can reduce costs and increase revenues. Furthermore, the costs of offshore wind may decrease over time due to technological learning.

8.6.1. Factors Influencing Revenue

The wind profile at a site determines the cost of energy and the revenue to a wind farm operator by determining the number of kWh sold. Since wind power scales with the cube of wind velocity, the velocity of the air is likely to be the most important single factor in determining the placement of offshore wind farms and their profitability. The strongest winds offshore of the U.S. occur in the Aleutian Islands in Alaska, off the coast of northern California and southern Oregon, and in the Atlantic Ocean off the southern and eastern coasts of Massachusetts. In all of these places wind speeds at 50 m average 8.8-11.1 m/s (USDOE, NREL, 2008). While these are the largest concentrations of strong winds, there may also be areas of class 7 winds at 80 m off the coasts of Texas, Louisiana, North Carolina and Long Island (Archer and Jacobson, 2005); however, these winds were not identified by some other studies (USDOE, NREL, 2008).

The CE is also determined by the time of the day in which these winds blow. Electricity is not equally valuable throughout the day and developers interested in site selection need to know not just the mean annual wind speed, but the time of day and time of year in which the wind is strongest.

Revenue is determined by costs of energy at the local level. In the U.S. the average retail price of electricity ranges from 4.92 to 20.72 ¢/kWh (USDOE, EIA, 2008). Thus an offshore wind farm may not be practical in Washington (average retail price of electricity is 6.14 ¢/kWh) but may be very profitable in Hawaii where the average price is over three times higher (20.72 ¢/kWh).

Revenue is also impacted by what other marketable products the wind farm generates. In states with Renewable Portfolio Standards (RPS), wind farm operators could sell renewable energy credits (RECs). States with RPS include most of the states with offshore wind potential with the exception of Ohio, Georgia, Louisiana and Michigan. The prices of RECs vary dramatically with the most expensive RECs being about 45 to 55 $/MWh in Massachusetts, Connecticut and Rhode Island.

The differences in local prices for electricity and RECs mean that the Cape Wind project may be able to sell its electricity for about 13 ¢/kWh (average wholesale price of electricity in New England in 2007 was 7.7 ¢/kWh; average REC price is 5.5 ¢/kWh), while the Galveston Offshore Wind project may only be able to sell electricity at half that rate (average wholesale price of electricity in Texas in 2007 was 5.7 ¢/kWh; average REC price is 0.5 ¢/kWh) (Wiser and Bolinger, 2008; USDOE, EIA, 2008). These differences in revenue could determine if a wind farm would be competitive with fossil fueled fired electricity or not.

8.6.2. Site Selection Impacts

Previously, we discussed the possible impacts of water depth and distance to shore on capital costs; however, other factors associated with the site selection will also impact capital costs, for example, seafloor geology. Most offshore wind farms have been established using monopiles. However, monopiles are impractical in rocky soil since they may require drilling. Suction caissons have been employed as foundations for some turbines and they have been installed in both clay and sandy soils, but, firmer substrates require larger pressure difference between the outside and inside of the caisson. Therefore, suction foundations may be impractical in some shallow water applications.

Areas with extreme weather events, and even areas with a high frequency of moderate weather events, can also influence costs. Moderate waves (above 2 m) can delay construction and affect the proportion of time that maintenance crews can access the turbines.

Hurricanes could dramatically influence the costs of construction and insurance. Current onshore towers are built to withstand 120 mph winds; hurricanes often have winds that significantly exceed this threshold. WEST, a company interested in building an offshore wind farm off the coast of Texas, has developed plans for a wind turbine that could withstand winds in excess of 150 mph (Schellstede, 2008); it is unclear how much this might add to the cost of a turbine. Given the frequency of hurricanes in the Gulf of Mexico and the 20 to 30 year lifetime of a wind farm, it seems prudent for any wind farm to plan on being impacted by one or more hurricanes over its lifetime.

8.6.3. Project Specific Impacts

The costs of installation are partly determined by how many of the components are assembled on land (Deepwater Wind, 2009). In some cases, developers have assembled components and even complete turbines on land and then shipped them to the installation site. This may decrease the time in which barges are needed but increase the sizes of the barges needed for construction. Barge costs are determined by the market; if wind farm development increases barge utilization then demand conditions will likely increase dayrates. Contracts with barges can be on either a turnkey or dayrate basis. Turnkey contracts transfer the operational risks associated with construction to the contractor; the party who holds weather related delay is determined by the terms of the contract.

8.6.4. Economies of Scale

The largest wind turbines in the world are built by two German companies, Enercon and Repower. Enercon is building a 6 MW prototype land based turbine while Repower sells a 5 MW turbine. Plans for a 10 MW vertical offshore wind turbine have also been reported. Physical principles suggest that these larger machines should be more expensive per kW than smaller turbines because the material needed for a turbine should scale with the third power of rotor diameter while the power should scale with the square of rotor diameter (Butterfield et al., 2007; Junginger et al., 2004). However, empirical data suggest that the cost per kW of capacity has stayed relatively constant with increasing rotor diameter due to technological innovation (Butterfield et al., 2007) and the weight of the blades and the nacelles has scaled with the exponents 2.3 and 1.5 respectively, rather than the cube as expected (Junginger et al., 2004). This, combined with the fact that operation and maintenance costs are lower for wind farms with fewer, larger turbines, means that as the scale of wind farms increases, the costs of energy may decrease (Grimley, 2007). These cost reductions reach a limit for land-based wind farms due to the high costs of transporting huge turbines and blades. For offshore turbines transportation over roadways is not an issue, and it is likely that the size of offshore turbines may continue to increase above 5 MW (USDOE, 2008a). We would expect that wind farms using large turbines would therefore be cheaper on a per kW capacity basis, but so far this has not occurred (Figure H.2).

We might also expect larger wind farms to be less expensive on a per MW basis than smaller wind farms (Dept. for BERR, 2004). This could occur through discounts with large turbine purchases, through learning associated with installation of foundations, through operation and maintenance efficiencies or through decreasing per MW electrical connection costs. However, the data for onshore wind farms do not seem to support this expectation (Wiser and Bolinger, 2008) nor do the data for offshore wind farms (Figure H.3).

8.6.5. Technological Learning

Musial and Butterfield (2004) predicted that the CE for an offshore wind farm in shallow water would decline from 54 $/MWh in 2006 to 32 $/MWh 2025 based on technological learning and independent of cost reductions through scale economies.

There are several ways in which technological learning could take place; it could occur through incremental developments, the development of new main components, or through the development of entirely new turbine concepts (Lemming et al., 2007). Incremental development consists of developing new methods for turbine installation, advanced blade materials, easier access to the turbines, and more reliable electronic components, and is expected to be the major source of future price reductions[23] (Lemming et al., 2007; ODE, 2007). Other options for technological cost reductions include the use of DC transmission, the mass production of jacketed structures, and the assembly of turbine components onshore (Junginger et al., 2004; Lemming et al., 2007; ODE, 2007).

8.7. Environmental Impacts of Offshore Wind Power

Offshore wind power has both positive and negative environmental consequences. The negative environmental consequences are generally local, whereas the positive environmental consequences are global and exist only insofar as offshore wind power displaces other forms of electricity generation. The environmental impacts studied in the Cape Wind EIS (USDOI, MMS, 2008a) are shown in Table H.5, but note that the U.S. Fish and Wildlife Service has objected that the data used to make the determinations in Table H.5 were not adequate (Bennett, 2006). In general, the environmental impacts of offshore wind are similar to those from onshore wind; however, offshore wind has additional environmental impacts, primarily associated with the effects of noise on marine animals, that onshore wind does not share.

8.7.1. Impacts on Birds

One of the primary concerns surrounding wind farms is the risk that they will cause excessive avian mortality through collisions. The birds most at risk of collision will be seabirds, and in some cases migrating passerines. While bird mortality increases due to the risk of colliding with offshore turbines, the rate of mortality is relatively low, from 0.01 to 23 mortalities per turbine per year (these data are from both on and offshore wind farms; Drewitt and Langston, 2006). On a per MW basis, fatalities range from 0.95 to 11.67 deaths per year (Strickland and Johnson, 2006). Altamont pass in California became notorious for its bird mortality. While the annual collision rate per turbine was low (0.02 to 0.15 collisions per year), mortality was still sizable due to the fact that 7000 turbines were involved and many of the birds killed were golden eagles,

[23] One example of this could be the learning that occurred during the Horns Rev installation. Eighty turbines were installed at Horns Rev. At the start of construction the average installation time was 3 days; by the end of the construction period an average of 1.4 turbines was installed per day (Junginger et al., 2004).

a charismatic species (Drewitt and Langston, 2006). These data suggest that the fatality rate may be highly dependent on site specific factors.

The estimates above were generally taken from studies in which mortality was measured by counting dead birds found near turbines and, in some cases, correcting for birds removed by scavengers. In the offshore environment counting carcasses is likely to be very difficult due to the fact that many carcasses will not be found (Bennett, 2006). At Nysted, a thermal imaging system was placed on one of the turbines and could monitor 30 percent of the swept area for bird collisions. Using these data, it was predicted that approximately 0.02 percent of birds would collide with turbines.

Wind farms can also pose barriers to birds. Birds often seem to avoid flying through wind farms; this likely decreases their mortality (Desholm and Kahlert, 2005). However, birds that avoid a wind farm must expend a significant amount of energy flying around it, especially since offshore wind farms can be quite large (tens of square miles). This could be of particular importance if a wind farm is located in between rookeries and feeding grounds (Drewitt and Langston, 2006).

Finally, wind farms can remove essential habitat from seabirds. Many seabirds have restricted areas in which they can successfully feed and in many cases these areas are shallow sand banks appropriate for wind farm development. If birds avoid wind farms, then even though the footprint of a wind turbine foundation is very small, very large areas of habitat may be inaccessible to birds. This seems to have occurred among diving birds at the Horns Rev wind park and long-tailed ducks at Nysted wind park. Similar patterns are seen for terns and auks at Horns Rev, although the trends are not significant (DONG Energy et al., 2006).

8.7.2. Impacts on Marine Mammals

Many cetaceans use echolocation to find food and many more communicate via acoustic signals. As a result many cetaceans, particularly porpoises, have very sensitive hearing which can be damaged by the loud noises associated with wind farms, particularly the sounds of pile driving. At the site of construction, the sound pressure level of pile driving a monopole for a 1.5MW turbine is 228 dB (Thomsen et al., 2006). Four-hundred meters away from pile driving the sound pressure level is 189 dB. This would cause hearing loss in seals. Hearing loss for porpoises would likely extend 1.8 km away from the source. Pile driving would be audible to porpoises and seals for at least 80 km and might cause behavioral responses up to 20 km away (Thomsen et al., 2006). This sound pressure level is similar to, but slightly less intense then, that used in naval sonar which has been implicated in the mass stranding of beaked whales (Thomsen et al., 2006). During wind farm operation the noise from the turbines may be detectable for porpoises and seals up to about 1 km from the source (Thomsen et al., 2006).

At the Nysted Wind farm the population of harbor and grey seals was monitored before, during and after construction. Wind farm operation did not seem to significantly impact seal abundance; however, piling driving operations that occurred at one foundation site (Nysted uses gravity foundations) did decrease the number of seals observed at a nearby breeding site. Also, while the total annual population remained stable, after construction fewer harbor seals were present on nearby land sites in June (the breeding season) but more were present in July and

August. This could suggest that fewer seals are using the area around the wind farm for breeding which could have an important effect on the viability of the population (Carstensen et al., 2006).

Harbor porpoises were shown to occur less frequently in the area around a wind farm during construction at both Nysted (Carstensen et al., 2006) and Horns Rev (DONG Energy et al., 2006). Presumably this is primarily due to animals fleeing the noise. At Horns Rev, the porpoises seemed to return following the construction period; however, even two years later porpoises at Nysted are less numerous then they were in baseline studies (DONG Energy et al., 2006).

8.7.3. Impacts on Fish

Wind farms could have both positive and negative impacts on fish. These effects could cascade up the food web to have either positive or negative effects on the birds and marine mammals that consume them.

As with marine mammals, fish can be very sensitive to loud sounds and could be displaced during wind farm construction; however, there is a great deal of variability among fish auditory systems and different species of fish will respond differently to noise from underwater construction. Furthermore, bottom-dwelling fish will be affected differently from fish swimming in the water column due to the different propagation of sound through sediment (Thomsen et al., 2006).

There have been few studies on the effects of pile driving on fish (reviewed in Hastings and Popper 2005). In general, these studies have placed fish in cages at various distances from the piles being driven and measured mortality and other injuries through non-microscopic necropsy. Abbott and Bing-Sawyer (2002) studied Sacramento blackfish and found that fish placed in cages close to the sound source (45 m) experienced more damage than animals further away and that damage was only found in animals exposed to 193 dB or more. CALTRANS (2004) studied shiner surfperch and steelhead and compared damage between fish experimentally exposed to pile driving and fish that were transported to the site but not exposed to noise. They found that fish exposed to pile driving noise experienced more damage than unexposed animals, but that there was no significant difference in mortality rates between control and experimental animals. CALTRANS (2001) also conducted an observational study of fish mortality during pile driving for the San Francisco-Oakland bay bridge and found dead fish out to 50 meters around the construction. Finally, Abbott (2004) and Marty (2004) studied the effects of a relatively small pile (2 feet in diameter) being driven close (32 feet) to cages of shiner perch, Chinook salmon and northern anchovies and they used control fish subjected to the same conditions but without noise. They found no difference in either mortality or pathology.

There have also been a few studies on the effects of noise on stress levels in fish. Chronic noise exposure is known to increase stress levels in humans with consequential effects on health. Smith et al. (2004) studied the effects of a continuous 170 dB noise on corticosterone (a stress hormone) levels in goldfish and found no statistically significant results.

More subtle effects on fish behavior could also occur. Engas et al. (1996) and Engas and Lokkeborg (2002), found that the catch rate of haddock and cod decreased in areas after air gun use but returned to normal several days later suggesting that fish left the area and gradually returned. Nedwell et al. (2003) calculated the zones around which salmon and cod would show significant avoidance behavior to be 1.4 km and 5.5 km, respectively.

The only clear conclusions which can be drawn from this research is that pile driving will effect fish; the degree of this effect will vary and is not at all clear. Very close to pile driving some mortality may occur for some species and fish may temporarily leave the area.

Wind turbines also create noise during operation. This noise would be of very long duration and, if intense enough could have significant ecological impacts. However, under normal conditions operational wind farm noise has been shown to be slightly above background noise, generally by approximately 5 dB in British wind farms (Nedwell et al., 2007).

Many species of fish are also sensitive to electric and magnetic fields which can be caused by buried underwater cables. Fish use their perception of electric and magnetic fields for orientation and prey detection. Species that contain magnetic material, potentially for navigational purposes include several species of economically important fish including yellow fin tuna, and Chinook and sockeye salmon (Öhman et al., 2007). There is some evidence that the fish in the area of the Nysted wind farm may be affected by the electromagnetic fields produced by the wind farm. Baltic herring, common eels, Atlantic cod and flounder all showed asymmetries in the catch rate on either side of the cables suggesting that the cables may retard migration (DONG Energy et al., 2006).

In addition to these negative effects, there has been some discussion of the potential for positive impacts from offshore wind farms on fish and fisheries. After construction of an offshore wind farm, turbine foundations could act as fish aggregating devices (FADs). The foundations could add three dimensional complexity to the environment and serve as a substrate for benthic invertebrates, thereby attracting fish. Offshore oil platforms are well known for this property. Although monopiles lack the structure of offshore oil and gas platforms, Wilhelmsson et al. (2006) have shown that they act as fish aggregating devices at the Yttre Stengrund and Utgrunden wind farms. At the Horns Rev and Nysted wind farms there was no clear difference between fish densities inside and outside of the wind farms (DONG Energy et al., 2006). The difference in these results is likely due to the different methodologies employed. The Swedish studies used scuba divers to monitor fish while the Danish studies used hydro-acoustic sampling. As a result, the Danish studies may have overlooked some of the smaller species observed in the Swedish wind farms.

8.7.4. Environmental Benefits of Offshore Wind Power

Wind power is considered to be among the most environmentally benign sources of electricity available today and it is important to consider the negative environmental impacts of wind power in the context of alternative sources of electricity. For example, concerns about the impacts of wind power on birds should be compared to the impacts of fossil fuel use on birds on a per MW basis.

Greenhouse Gases

The primary environmental benefit of wind power is its negligible contribution to global climate change. The only greenhouse gases produced by the establishment of a wind farm are those used in the construction and operation of the wind turbines and farm. The greenhouse gases released from construction and operation of an offshore wind farm are likely to be dominated by CO_2 released from the ships used in construction of the wind farm and the manufacturing of the steel and concrete used in the turbine towers and foundations. To our knowledge there is no estimate of these emissions for offshore wind farms, but for onshore wind farms these emissions decrease the CO_2 offset by 1 to 2 percent (White and Kulcinski, 1998). It is not clear whether offshore turbines would have higher or lower per MW CO_2 output from construction. In general, transportation via ship is more efficient than over land, but the operation and maintenance emissions may be higher for offshore wind. Assuming an offshore wind turbine replaces electricity generation from fossil sources at a rate equal to that for onshore wind farms, then each MW of wind capacity should displace about 1800 tons of CO_2 per year (AWEA, 2008).

It is extremely difficult to predict the effects of climate change per ton of CO_2. While we can predict a per MW bird mortality associated with wind power, we cannot make a comparable prediction for fossil fuel use. Studies have indicated that climate change may be associated with high rates of species extinction. Climate change is predicted to cause between 11 and 45 percent of all species to become extinct (Thomas et al., 2004). For birds, the subject of so much concern over wind power, it is estimated that 950 to 1800 species of terrestrial birds (out of 8750 studied) will be threatened due (in part) to climate change (Jetz et al., 2007). It is critically important, however, that there has been very few studies of the adaptation of biodiversity to climate change, thus these estimates must be taken as preliminary (IPCC, 2007). Still, the fact that climate change may imperil the survival of species, especially species endemic to high and low altitudes and latitudes and restricted geographical ranges, is in contrast to wind power which has no demonstrated population or species level effects on biodiversity.

Water

In many parts of the U.S. water resources are stressed. The six world climate models used in the Intergovernmental Panel on Climate Change (IPCC) generally predict that the U.S. will become drier by 2050. One of the models predicts that precipitation over virtually the entire U.S. will decline by over 30 percent while the other five models show more modest declines (IPCC, 2007). Forty-eight percent of total water withdraws and nine percent of total water consumption (68 billion liters per day) is used by thermoelectric power plants (powered by coal, natural gas, nuclear, oil and biomass; USDOE, 2008a). Ethanol production also uses large quantities of water, from 3.5 to 6 liters of water for every liter of ethanol produced (Keeney and Muller, 2006). Wind power directly uses no water. Per kWh, the amount of water used in fossil fueled plants ranges from about 0.2 to 0.6 gallons depending on the technology employed (Clean Air Task Force, 2003). Assuming a 40 percent capacity factor, one MW of offshore wind power can offset the use of between 0.7 and 2.1 million gallons of freshwater per year.

Value of Ecological Benefits

Onshore and offshore winds have nearly identical ecological benefits on a per MWh basis. We can attempt to place a dollar value on the ecological services, in terms of water unused and carbon not emitted, of offshore wind power relative to traditional fossil fueled power. The actual costs of offsetting a ton of carbon are not known, but governments have set up trading systems in which offsets are exchanged. The costs of these offsets will be set by supply and demand, and are expected to increase in the future. Current prices for the offset of one metric ton of CO_2 are around \$30. Each MWh of coal-fired electricity produces 0.839 metric tons of CO_2 (Sims et al., 2003). Thus, per MWh, the value of avoided CO_2 emissions may be about \$25.

8.8. Ecological Mitigation

8.8.1. Mitigation through Site Selection

Potential sites are avoided due to their potential impacts on the environment. Certain areas are known to be bottlenecks on the migratory routes of large numbers of birds. Cape May, New Jersey, Delaware Bay, Grays Harbor Washington, Point Reyes, California, and the Barrier Islands of Louisiana are all important areas for avian migration and may be considered unacceptable for offshore wind power development (Lincoln et al., 1998). Similarly, planners for the LIOWP took the migration routes of Right Whales into consideration in selecting a site. Whale migration routes will likely need to be considered on the Pacific coast as well.

Placing offshore wind farms near nesting sites for seabirds may also be ecologically hazardous. Seabirds generally avoid using the Horns Rev wind farm and direct mortality from collision with turbines is relatively rare and in many cases not significant. However, because seabirds avoid entering offshore wind farms, their existence may reduce available foraging habitat or force birds to expend energy to fly around the wind farm (Desholm and Kahlert, 2005). Both of these could have population level impacts on bird species. Offshore wind farm construction could also have similar impacts on nearby populations of marine mammals.

From the perspective of conserving biodiversity, it is perhaps most important for developers to avoid areas considered essential habitat for threatened or endangered species. The Endangered Species Act requires that critical habitat for any listed species be identified and it requires federal agencies that permit activities consider the effects of permitting on these habitats. While there are procedures in which the government may permit activities that are detrimental to the critical habitat of an endangered species, it would seem prudent for developers to exclude critical habitats of endangered species from development plans, if not out of a perceived ethical responsibility for conservation, then out of the risk of the failure of the permitting process and the associated financial losses.

The areas of critical habitat for species managed by NOAA are listed at http://www.nmfs.noaa.gov/pr/species/criticalhabitat.htm and species managed by FWS are listed at http://crithab.fws.gov/. The critical habitat of the North Atlantic Right Whale and the Stellar Sea Lion, both managed by NOAA, are the most likely to influence offshore wind placement. The critical habitat of the North Atlantic Right Whale includes areas off the coast of southern

Georgia and the Atlantic Coast of Northern Florida as well as areas off the Northern and Eastern coasts of Cape Cod. The areas of critical habitat that may conflict with offshore wind power development for the Stellar's sea lion consist of five small zones off the coast of Northern California and Southern Oregon.

The impacts on local culture should also be considered. One of the primary criticisms of the Cape Wind project is that it will spoil the views from historic areas. Similarly, some areas of interest for offshore wind development may be located near shipwrecks. These issues should be noted by wind power developers for two reasons. First, the BOEMRE, in their guidelines on development of the OCS, adopted a policy of consulting with State Preservation Authorities before permitting development and it is therefore possible that BOEMRE would decline a permit for offshore wind energy if there were significant cultural issues. Secondly, even if BOEMRE were to allow development, construction can be seriously slowed by local community resistance. For example, the Cape Wind project will, if completed, have taken at least a decade to develop and have required at least one protracted legal battle (*Alliance to Protect Nantucket Sound v. United States Army*). In contrast, WEST's plans to build a wind farm off the coast of Texas have proceeded rapidly, despite less favorable wind conditions. This may be due to acceptance by the local community, many of whom are familiar with offshore structures from experience with the oil and gas industry (Patterson, 2005).

8.8.2. Mitigation through Technology

Most of the offshore wind turbines constructed to date have used monopole foundations. The ecological effects of the piling operations are a concern; however, there are alternatives to pile-driven foundations. One option would be to use gravity foundations, as were used in the Nysted and Middlegrunden wind farms. Gravity foundations are simple concrete structures with large diameter bottoms that rest on the sea floor. They weigh thousands of tons and use their weight to stabilize the turbine. Gravity foundations do not require piling operations and therefore have less potential to disturb marine mammals and fish. Also, gravity foundations have more three dimensional structure than monopiles; this may provide additional habitat for benthic organisms.

Another alternative would be to use suction foundations, such as those considered in the Beatrice demonstration project. Suction foundations are simple steel baskets that are placed on the seafloor and form a seal with the ocean bottom. Suction is then applied to the inside of the basket and the resulting pressure difference causes the basket to bury itself in the sediment, much like a driven monopole (Byrne et al., 2002). Again, installation is much quieter allowing for fewer environmental effects.

Technologies are also being developed to allow the use of deeper water. Using deeper water would allow offshore wind farms to be sited further from shore, increasing the wind speed and decreasing the possibility of conflicts with local human and animal populations. A survey conducted in New Jersey showed visitors and residents simulated images of offshore wind farms at varying distances from shore and found that as the distance increased the percentage favoring development increased (Mills and Rosen, 2006). Deep water turbines could be placed over the horizon and thus be invisible from shore. This would also decrease their impact on seabirds which generally do not feed in the open ocean, and on migratory birds, which, with the exception of birds flying over the GOM, do not migrate over open ocean. Additionally, these turbines are placed on floating foundations that will likely have fewer environmental impacts during construction.

One of the leading developers of floating foundations for offshore wind turbines is Blue H Technologies. They have recently installed an offshore wind turbine in 108 meters of water 20 km off the coast of Italy and also applied to BOEMRE for a permit to study the potential for a wind farm 23 miles off the southern coast of Cape Cod (Blue H, 2009). If this technology becomes economically viable it could decrease conflicts with coastal communities and would lessen the environmental impacts of wind farms.

8.9. Conclusion

The higher economic costs of offshore wind power relative to onshore wind power could be justified if the ecological or social costs of offshore wind were significantly different from onshore wind power, but this seems not to be the case. Both on- and offshore wind power face local opposition due to user conflicts. The ecological impacts of offshore wind power affect a very different ecosystem than onshore wind power and, as a result, their ecological impacts are not directly comparable. However, like onshore wind, it is clear that offshore wind power does have ecological impacts with the potential for population level effects.

Decreasing commodity costs or legislation capping greenhouse gas emissions could increase the profitability of offshore wind but would not change the fact that onshore wind will be a less expensive alternative, even when transmission costs are included. Until land use conflicts in high wind onshore sites become severe, or the technology develops so that the higher offshore winds balance the higher costs of installation, there seems to be little incentive for a large offshore wind industry in the U.S. In sum, we do not envision offshore wind producing a significant portion of the U.S. electricity production until at least 2020.

It is much more difficult to analyze the ecological and economic costs and benefits of offshore wind power relative to fossil-fueled power. Including a premium on coal-fired power of $25/MWh to offset emissions may make coal and offshore wind power nearly price competitive, depending on the specific capital costs of offshore wind. This $25/MWh premium would give coal and offshore wind similar greenhouse gas emissions; however, coal would still use more water than offshore wind and would be associated with significant health effects through particulate emissions and additional ecological impacts through sulfur emissions. However, this would be balanced against the ecological impacts of offshore wind in terms of bird and bat mortality and marine mammal impacts, which possibly can be mitigated. Thus, it is not clear that offshore wind is preferable to coal fired power, even if the emissions from the coal plant are offset. To make such a comparison would require valuing the health and acidification impacts of coal fired power against the environmental impacts of offshore wind, something that is beyond the scope of the present work.

Based on the analysis in this chapter, it seems clear that the economic and ecological costs of offshore wind power are site specific. These costs can be mitigated with current technology and detailed site selection. It therefore seems imprudent to conclude that all offshore wind development is inferior to all onshore wind development or fossil fueled power. Instead, a more nuanced approach which weighs the site specific costs and benefits of offshore wind power is necessary. In some cases, offshore wind power may be able to cheaply produce electricity with negligible environmental impacts; however, in many more cases, offshore wind power will be more expensive than its competitors, even when the costs of carbon offsets are included.

9. REVIEW OF OFFSHORE WIND POWER REGULATORY ISSUES

In this chapter, we discuss the ways in which regulators could encourage the development of an offshore wind power industry that is economically viable and that considers the ecological costs and ensures public benefits. This chapter does not deal with the various laws with which a regulatory system would have to comply; for these issues we direct the reader to Santora et al. (2004) or Firestone et al. (2004). While it will be a challenge for regulators and developers to negotiate this complex milieu of already existing laws and regulations, we focus on the leases for offshore wind and their regulations. We first discuss the relevant European regulatory and lease frameworks for offshore wind power and then describe three relevant leasing systems in the U.S. We use these descriptions to discuss issues and tradeoffs involved in the development of an alternative energy leasing policy on the OCS.

9.1. Introduction

Onshore wind energy is experiencing rapid growth in the U.S. and around the world (Wiser and Bolinger, 2008) and offshore wind energy development is experiencing rapid growth in Northern Europe, yet despite significant potential, there are currently no offshore wind parks in the waters of the United States or Southern Europe. In part, this is due to the superior winds and shallow waters of the Baltic and North Seas, and the subsidies offered by European governments to offshore wind developers. The lack of a comprehensive regulatory system in the U.S. and several European countries may also be slowing development.

Several European countries as well as some U.S. coastal states and the U.S. federal government are currently developing regulations for offshore wind power. In U.S. federal waters, the BOEMRE is the lead agency in coordinating offshore wind development. The Energy Policy Act of 2005 gave the BOEMRE authority to lease offshore wind energy on the OCS. In December 2007, BOEMRE published its record of decision (ROD) in response to the programmatic Environmental Impact Statement (EIS) on alternative energy uses on the OCS (Luthi, 2007), and in July 2008, BOEMRE proposed regulations for an offshore alternative energy program and asked for public comments.

When establishing a regulatory system it is often difficult to quantify the costs and benefits involved and to create a system that is comprehensive, yet flexible and robust to future uncertainty. All regulations are a series of tradeoffs in which regulators must balance conflicting policy goals and uncertain outcomes. In the case of offshore wind, regulators must balance encouraging a low-carbon, renewable energy technology with impacts to local ecosystems and viewsheds and potential conflict with other offshore users (Bisbee, 2004). Each regulatory decision will either encourage or discourage offshore wind development and could affect the rate of development and its eventual scale.

The regulatory system most applicable to offshore wind energy may be the regulation of the offshore oil and gas industry since in both cases private developers seek to produce energy, a commodity needed by the public, through the use of public marine resources. However, there are significant differences between these two industries. In the offshore wind industry, developers must take out large loans and spend several years before any revenue is generated.

When they do begin generating income, the income will be spread out slowly over many decades, and the risk to revenue stream can come from many sources- environmental, market and regulatory. The difference between the cost and sales price of offshore wind energy is quite low. In contrast, the offshore oil industry, although requiring significant capital, generally produce large amounts of revenue quickly and recoup initial investments within the first few years of production. Additionally, while the price of oil is highly variable, the ratio of sales price to cost is far higher than it is for offshore wind energy. As a result, regulations, especially the production of site specific EISs and lease fees that may have little impact on the oil and gas industry, could cripple the offshore wind industry (Schellstede, 2008).

The major issues regulators will have to address include: 1) lease terms and conditions, including phases of development rights, lease fees, and the length of leases; 2) competition and the approval process, including how to select sites and what criteria to use in permitting leases; 3) environmental impact assessments, including data requirements and alternative methods for NEPA compliance; 4) monitoring operational issues, including safety and environmental compliance; and 5) ensuring decommissioning. A brief synopsis of the ways in which several regulatory authorities have dealt with these regulatory issues is summarized in Table I.1.

9.2. Regulatory Systems in Europe

Many European nations have either no method for regulating offshore wind farms or have little successful experience in promoting their development. The UK and Denmark are two exceptions. They both have several large operational offshore wind farms and have several others under construction and in planning stages. In this section we review the regulatory regimes of these two nations along with two other nations, Germany and the Netherlands. Both Germany and the Netherlands have less formalized offshore wind regulations which allow developers more freedom but which have so far resulted in relatively few operational wind farms.

9.2.1. United Kingdom

The submerged land of the United Kingdom's territorial sea is the property of the Crown Estate (Scott, 2006). As a result, the Crown Estate must grant a lease for offshore wind development within the UK's territorial sea. Beyond the territorial sea, the Crown Estate must still grant a license for development. While the Crown Estate is the landowner, the Department of Business, Enterprise and Regulatory Reform (BERR), formerly Department of Trade and Industry, is the lead government agency involved in offshore permitting (Peloso, 2006).

The Crown Estate has thus far conducted two "rounds" of leasing. The first round took place in April 2001 and resulted in 18 agreements between the Crown and energy developers. The second round took place in December 2003 and resulted in 15 agreements (The Crown Estate, 2008). A third round was announced in June 2008 (Smith, 2008). In all rounds, the agreements were only with the Crown Estate and developers had to obtain permits with other government agencies (Peloso, 2006; Scott, 2006). In the first round, developers were required to choose sites of interest. In the second round, developers were required to submit proposals that fell within one of three strategic areas designated by the government, areas for which a Strategic

Environmental Assessment (SEA; similar to U.S. Programmatic Environmental Impact Statement) had been completed.[24]

In order to participate in the round two leasing process, companies registered by submitting a ten-page business development plan which included potential areas of developmental interest. The Crown Estate sent instructions for tenders to registered companies. The companies then submitted tenders composed of financial information, a description of the project, a 50 page business development plan and a decommissioning plan (The Crown Estate, 2008). This entire process took about 9 months to complete.

The Crown Estate used four criteria to evaluate tenders including the financial and technical capacity of the applicant, the development plan (i.e. what the applicant was offering), the business development plan, and the decommissioning plan. The highest weight was given to the business plan which included financial plans, plans for obtaining other required permits, and plans for construction and operation. This section of the tender was to form the basis of the legally binding lease. The development plan also included a description of the environmental site specific studies the applicant would conduct in the creation of the SEA. Priority for competing applications was given to the most qualified applicant; financial considerations from the perspective of the Crown were not considered. Instead flat rate fees were used. All applicants were required to pay an application fee of £2,500. If applicants were successful they were required to pay a one-time option fee of £25,000 to £500,000 depending on the size of the development and roughly equal to £2,000 to £5,000 per km^2. This option fee was used to support research and education projects committed to the furtherance of the offshore wind industry (The Crown Estate, 2008).

Leases provide developers seven years to obtain other necessary consents. In addition to the Crown Estate, developers must obtain a permit from the BERR for any electrical generating project over 1 MW in capacity (DTI, 2004). In its permitting decision, BERR primarily considers the navigational issues raised by wind farms. BERR may not grant a permit in any area essential to international navigation and must consider the cumulative impacts of other permitted wind farms on this decision. BERR also has the authority to close the area in and around a wind farm to public navigation.

Offshore wind projects require licenses from the Marine and Fisheries Agency (MFA). The MFA is the agency tasked with evaluating the environmental impacts of a proposed wind farm by executing the provisions of the Food and Environmental Protection Act (FEPA) and Coast Protection Act (CPA). The MFA issues guidance on the requirements for a SEA, which must be completed before MFA approval (DTI, 2004). MFA evaluates hydrological effects, effects on fisheries and other marine life, and effects on specially designated habitat.

BERR is also responsible for ensuring decommissioning of offshore structures. The developer must submit an acceptable decommissioning plan to BERR. The decommissioning plan may make allowances for repowering or reuse of facilities for other renewable energy generation. The decommissioning plan may leave some components in place (buried cables, monopiles,

[24] As a result of the SEA, BERR removed any area within 8 km of the coast, as well as any shallow water, from consideration for wind development.

scour protection) if removing them would cause an undue ecological or economic burden (DTI, 2006). BERR requires that the developer provide some financial assurance that decommissioning will occur according to the agreed upon plan. BERR will accept financial assurances on a case-by-case basis, but generally accepted assurances include cash, surety bonds, or letters of credit. Liability for damages from the remnants of a decommissioned wind farm will remain with the owners in perpetuity.

BERR did not publish its plan for decommissioning until late 2006, well after several offshore wind parks were operational. This, combined with the changes between the first two rounds of offshore leasing, suggests that the UK continues to modify its regulations as the industry develops.

Thus, in the UK there are three main agencies, the Crown Estate, the BERR and the MFA, each of which are tasked with evaluating different components of offshore wind development. This system has been thought of as too complex and inferior to a "one-stop shop" approach set up by Denmark (EWEA, 2007; Firestone et al., 2004); however, the UK offshore wind industry seems to be developing well despite this criticism.

9.2.2. Denmark

Denmark has been leading the world in wind power usage for centuries and they continue to do so, especially in the offshore environment. Denmark established the world's first offshore wind farm at Vindeby in 1991, and the second at Tuno Knob in 1995. They also established the first commercial scale offshore wind farm at Middelgrund in 2001 (see Chapter 8).

One reason for the success of the offshore wind power sector in Denmark is government policies on offshore wind power. Offshore wind development in Denmark is regulated almost exclusively by the Danish Energy Authority (DEA). This is different from many other countries in which offshore wind developers have to interact with a variety of governmental agencies. The DEA provides "one-stop shopping" for wind energy developers (DEA, 2007) and provides centralized planning and coordination for the promotion of offshore wind power.

The methods for gaining DEA approval have evolved over the past several years, but proceed through either a tender or open-door process. In the tender process, the DEA requests proposals for tenders at a specific site that has been pre-screened by DEA and the DEA releases a desired capacity. Interested applicants are pre-qualified based on financial, legal and technical qualifications. Pre-qualified applicants are asked to submit tenders for a wind farm of specific capacity. The tenders are evaluated primarily on the basis of the feed-in price required for the project. The winner of the tender process must then complete an EIS and may complete preliminary studies. However, this requirement can be waived if a satisfactory EIS has already been conducted in the site selection process. The winning bidder is obligated to build the wind farm (DEA, 2007; Peloso, 2006).

The open-door process involves an interested party applying to the DEA for a permit without a specific request by DEA and outside of the areas that have been pre-screened by the DEA. After the DEA receives the application, they will invite other interested companies to apply for the development of the same area, ensuring competition. As before, an EIS is conducted by the applicants. The DEA has so far not implemented the open-door process (DEA, 2007; Peloso, 2006).

The feed-in prices can be quite high. The recent Rodsand II agreed upon feed in price of electricity is 13.2 ¢/kWh. The Rodsand lease lasts for 25 years and includes a permit to conduct preliminary studies as well as a permit to build and operate a wind farm. The time between the request for tenders and the deadline for submitting tenders can be quite short; in the Rodsand case it was just under two months (DEA, 2008).

There is no national codification of operational issues. Instead, the winning bidder is required to submit safety, decommissioning and environmental monitoring plans and is then required to carry out these plans. The developer is also required to submit an annual report summarizing the environmental studies carried out that year (DEA, 2008).

9.2.3. The Netherlands

The Dutch have set a goal of offshore wind farms with a total capacity of 6000 MW. Unlike the UK and Denmark, the Dutch set specific areas in which offshore development is excluded. Interest in a wind farm is initiated by the developers who send a proposal to the Ministry for Transport, Public Works and Water Management (Mast et al., 2007). The ministry replies with guidelines for the permit request and makes the proposal public. The permit request must include plans for construction, decommissioning, and an EIS. If granted, the permit allows the developer two years to complete construction. Additional permits for running cables to shore and across the shore are also required.

In the Netherlands developers are not pre-qualified; however, the requirement to complete construction within two years and the need for an EIS are intended to discourage speculation. The first-come, first-served method of awarding licenses virtually eliminates competition for sites. There is no competition among proposals which best serve the national interest, instead, the only competition is to be the first to submit a suitable application. The Dutch do not institute fees for leases, but developers must pay for the EIA; again this is thought to discourage speculation (Mast et al., 2007).

In 2006, the Dutch had a subsidy for offshore wind projects of 0.097 € ($0.15) per kWh. However, the Dutch government decided that their renewable energy goal would likely be met without the subsidy and were worried that the subsidy would cost too much given the growing interest in offshore wind. Therefore, they set the subsidy to zero in late 2006 (Mast et al., 2007). In late 2007 and early 2008 the Dutch government developed a new renewable energy premium program in which renewable electricity generators are paid a premium over the first ten years of operation. The premium depends on the technology used and the price of electricity and has not been codified for offshore wind, but for onshore wind it is €0.028 ($0.044) per kWh (EREC, 2007a).

9.2.4. Germany

Germany has permitted more offshore wind parks than any other European state, but no wind farms are currently operational in German waters. In Germany, the provinces control the waters up to twelve miles from the shore while the federal government controls the rest of the Exclusive Economic Zone (EEZ). Most offshore wind projects in Germany are expected to occur in federal waters; however, as in the U.S., the German states will have input in the permitting process, especially the permitting of transmission cables (BSH, 2008).

Offshore wind project approval in Germany is a non-discretionary action of the German Federal Maritime Agency (Bundesamt fur Seeschiffahrt und Hydrographie, BSH). That is, German law prescribes conditions for the rejection of offshore wind projects. The only duty of the BSH is to determine if those conditions exist. If they do not, the developer has a legal right to develop the project (BSH, 2008). These conditions are that the project does not constitute a danger to navigation and does not pose an unacceptable risk to the environment.

The consent procedure begins with the developer submitting an application to BSH. BSH then solicits comments from other government agencies, principally the regional waterway and shipping authority which also has to give regulatory approval. There is then a second round of comments solicited from a larger group of stakeholders including the public. After this second round of commenting the developer is invited to hold a conference in which the developer presents their plans for development and the scope of the required environmental data is determined. The developer conducts an EIS and an analysis of the potential danger to navigation caused by their proposed wind farm. After receipt of these documents, BSH passes them along to other relative authorities and makes them available to the public. BSH then decides if the proposal meets its criteria. At the same time, regional waterway and shipping administrators determine if the project poses a threat to navigation (BSH, 2008).

If the project is approved by both the BSH and the regional waterway and shipping authority, BSH approves the project for a term of 25 years. Construction must begin within 2 ½ years and the developer must furnish a bond for decommissioning (BSH, 2008). The developer is guaranteed a fixed price for electricity under the feed-in-tariff which starts at about 9 euro cents ($0.14) per kWh (EREC, 2007b). The price declines slowly over time.

There are no allowances for competition in the German system. If two developers submit applications for the same area, the first complete and acceptable application is granted (BSH, 2008).

The German system has been successful in permitting offshore wind projects, but thus far, dismal in their construction. This could be due, in part, to the fact that the only competition is to be the first developer with an acceptable development plan. Thus, developers have an incentive to complete applications for as many areas as possible, as quickly as possible.

9.3. U.S. Programs

Two conceptual models for the regulation of offshore wind power are presented in Figures I.1 and I.2 and represent the regulatory scheme for offshore wind energy in Texas (Figure I.1) and the Bureau of Land Management's (BLM) regulatory structure for onshore wind (Figure I.2). These models depict two ends of a spectrum of methods of regulation. Their main differences are whether the government or the developers choose the sites for development and if the government seeks to encourage competition among developers for the maximum financial benefit to the public (USDOI, BLM, 2006; Texas General Land Office, 2007a).

The fact that two very different programs were developed nearly simultaneously in the U.S. suggests that there are a number of feasible options for regulation. One reason for the difference between these two regulatory frameworks could be the relative interest in profit of the two agencies. The BLM stated that the development of onshore wind resources should have little budgetary impact and that their primary purpose is not to generate income for the government but to encourage wind energy development, consistent with the Energy Policy Act of 2005. The State of Texas also seems interested in the development of an offshore wind energy industry; however, they seem to be equally interested in maximizing the monetary benefit to the state (Patterson, 2005).

9.3.1. BLM Guidelines

The BLM manages wind energy development on federal land. In 2003 they began the process of conducting a programmatic EIS. The EIS was released in June of 2005 and an Instruction Memorandum implementing the Record of Decision was published in August 2006 (USDOI, BLM, 2006).

The BLM policy is designed to encourage the "development of wind energy in acceptable areas" (USDOI, BLM, 2006). Applicants may apply for a right-of-way for either a single meteorological tower, a series of meteorological towers in a larger area or commercial development. Applications for testing are conducted on first come basis (i.e. not competitively) and competing applicants for commercial energy development will be encouraged to form a cooperative agreement. Competitive leasing may occur if deemed appropriate in specific areas (USDOI, BLM, 2006).

A right-of-way for a single meteorological tower will last for three years and cannot be extended. The rental fee is $50 per year. The right-of-way does not establish any preferential rights to future wind energy projects in the area, and BLM may authorize multiple right-of-ways in the same area to multiple parties. The applications for meteorological monitoring should be processed within 60 days and are subject to minimal cost recovery fees (USDOI, BLM, 2006).

A right-of-way for a larger site lasts for three years but has provisions for extension beyond the three year limit. The right-of-way precludes other wind energy development in the area over the three year term of the lease. However, the holder establishes no right to commercially develop the area. As part of the application approval, BLM may consult with the National Renewable Energy Lab to determine if the proposed number and location of monitoring sites is sufficient to accurately predict future wind conditions. If BLM determine that the application will adequately quantify the wind resource, then a NEPA process begins. The rental fee will be determined by the total project area (i.e. the area that excludes competing development) and will be $1 per acre or $1000, whichever is greater. Bonds are discretionary, and data collected is proprietary, but may be made public if the holder applies for commercial development rights (USDOI, BLM, 2006).

The right-of-way for commercial development is not term-limited and is expected to last at least 30 years. The BLM retains the right to permit other compatible land uses over the term of the lease. The rental fee is $2,365 per MW of capacity per year and is phased in over the first three years of the project. This rate is designed to be a 3 percent royalty on production, assuming a 30 percent capacity factor and a 3 ¢/kWh sales price. It should be noted that the assumed 3 ¢/kWh sales price is below the average sales price of wind generated electricity (Wiser and Bolinger, 2008), and as a result the royalty is actually less than 3 percent. The royalty should add about 0.09 ¢/kWh to the cost of generating electricity (USDOI, BLM, 2006).

To ensure that speculators do not unduly control wind resources, applicants are required to provide information on their technical and financial capabilities. Additionally, the facilities for the monitoring of a wind resource must be constructed within 12 months of the approval of the application and the construction of wind turbines must commence within 2 years of the approval of an application (USDOI, BLM, 2006).

The NEPA process for BLM wind energy decisions will generally end with either categorical exemptions (CX) or environmental assessments (EA). CXs may be applicable for site monitoring applications while environmental assessments, building off of the programmatic EIS developed by BLM will be sufficient for most wind farms unless there is either significant public controversy or a determination of significant adverse impacts. Additionally, it would be acceptable to consolidate local and state environmental reviews with the NEPA process (USDOI, BLM, 2006).

9.3.2. Texas Offshore Wind Program

Because of its Spanish history, Texas' waters extend 3 marine leagues (9 nautical miles) offshore of the Texas coast (as opposed to 3 nautical miles for most other states; Florida's waters also extend three marine leagues while Louisiana's extend three imperial miles, slightly more than three nautical miles). As a result, Texas has been able to develop its own offshore wind leasing program which has evolved over the past several years. In 2005, the Texas General Land Office (GLO) signed an agreement with Galveston Offshore Wind (a subsidiary of WEST) for an 11,355 acre lease seven miles off the coast. In 2006, the GLO signed an agreement with Superior Renewable Energy (later a subsidiary of Babcock and Brown) for a 40,000 acre lease. Neither of these leases were conducted competitively. However, in October 2007, the GLO conducted a competitive leasing program and awarded WEST leases on four tracts of land totaling 73,000 acres. WEST was the only bidder, although there was interest from one other firm (Schellstede, 2008). The terms of both the competitive and non-competitive leases were similar, with the major difference being an increase in land rental rates from $10,000 to $20,000 per tract per year during the site testing and construction phases (Texas General Land Office, 2007a and b).

In the recent competition, the GLO released a set of bidding instructions stipulating which areas were available for lease, the minimum size (in MW) of the development and the minimum royalty rates. The GLO stated that the winning bidder would be the highest bidder that met or exceeded the minimums. The minimum lease rates were $20,000 per year during site testing and construction, then a gradually phased in royalty that varied from 3.5 to 5.5 percent of gross revenue. There was also a stipulation that set minimum annual royalties on a per MW of installed capacity basis which would apply only if they were greater than the royalties as a percentage of gross revenue (Table I.2). The term of the lease was 30 years (Texas General Land Office, 2007a and b).

The lease allows for phased access in which the lessee is first given research rights and then granted construction and operation rights. Within 60 days of the start of the lease, the lessee must submit a research plan to the GLO for approval. This must include a description of environmental studies and environmental assessment which the developer will undertake. After this initial research plan, the lessee must submit a quarterly Phase 1 progress report to the GLO, then submit a final report and a production plan to the GLO. The production plan must contain language that affirms that the lessee will either conduct an EIS if required by the Army Corps of Engineers, or else submit a mitigation plan to the GLO. In addition the production plan must contain economic analyses, the construction schedule and a final description of the project. Once the production plan is approved, the lessee may begin construction. During construction the lessee must submit progress reports to the GLO quarterly and the lessee has 36 months to complete construction (for the first 250 MW of capacity). Thus, the initial competition and lease gives the lessee the rights to both site assessment and development (Texas General Land Office, 2007a and b).

The lessee is required to provide the GLO with either a surety bond, a letter of credit, or a cash deposit before undertaking construction. The lessee sets the price of this bond, with approval from the GLO. The lessee owns all improvements on the site; however, the GLO has the right to receive the turbine foundations for use as artificial reefs upon cessation of production (Texas General Land Office, 2007a and b).

The lease contains stipulations whereby the lessee is exempted from payments in the case of Force Majeure. The lease does not include stipulations for repowering of the site (Texas General Land Office, 2007a and b).

9.4. BOEMRE Regulations

9.4.1. Lease Terms

BOEMRE released final regulations in April 2009 (USDOI, MMS, 2009). The regulations consist of a two tiered system in which developers can apply for either a limited lease or a commercial lease. A limited lease would be term limited to 5 years and would confer no developmental rights nor any preference for later commercial leases. BOEMRE anticipates that limited leases will primarily be used for technology evaluation and does not advocate their use for commercial operations.

Commercial leases would be for 30 years and would include a 6 month planning period, a 5 year assessment period and a 25 year construction and production period. The developer would be allowed to cancel the lease if site assessment showed the lease area to be insufficient for development and would be required to submit a site assessment plan at the beginning of the lease and a construction and operations plan in order to proceed to the commercial development phase of the lease (USDOI, MMS, 2009).

BOEMRE will collect two types of payments from commercial leaseholders, a rental fee of $3 per acre and a royalty of 2 percent of estimated gross revenue phased in over the first two years of operation.[25] In addition to royalties and rental fees, BOEMRE may also charge processing fees on a case-by-case basis. This may be particularly likely in the case of site-specific EIS (USDOI, MMS, 2009).

9.4.2. Competition and Approval Criteria

The lease process would begin with BOEMRE gauging competitive interest in a site. BOEMRE may begin this process by issuing a call for information and nominations of areas to be leased, or may identify an area that a developer has expressed interest in. If BOEMRE issues a call for nominations it will then evaluate the nominations, determine the area to be leased and issue a sale notice. The sale notice would notify the public of the lease location, invite interested parties to submit lease applications, and would specify how competing applications will be judged (USDOI, MMS, 2009).

If there is competitive interest, BOEMRE will conduct an auction. Commercial leases would be evaluated based on either the size of a cash bonus bid or the royalty rate. One of the two variables would be fixed to allow for straightforward comparisons. Limited leases would be evaluated only on the basis of a bonus bid. BOEMRE would not consider the technical or economic feasibility of competing projects, nor would it dictate the electrical capacity of development. BOEMRE will conduct competitions through either a sealed, single round bid process, a live or electronic auction, or some combination of these methods. In the oil and gas leasing system, sealed bidding is the dominant auction method (USDOI, MMS, 2009).

If there is no competing interest, BOEMRE will issue a noncompetitive lease through a negotiation process (USDOI, MMS, 2009).

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[25] Limited lessees would only pay the rental fee. BOEMRE studied the effects of this proposed rate by simulating 73 offshore alternative energy projects. They found that 55 of the 73 projects would be economically viable, and that economic viability was unaffected by the proposed rate. They conducted a similar analysis of three hypothetical offshore wind farms built in 2010 or 2020 and found that the government's share of net revenue was 40 percent for the wind farms constructed in 2010, but 15 percent for those constructed in 2020. Finally, BOEMRE compared the revenue to the government through rent and royalties to the Production Tax Credit (PTC). They found that the royalties they assessed reduced the value of the PTC by at most 15 percent (USDOI, MMS, 2009).

9.4.3. Environmental Analysis

BOEMRE will generally conduct two stages of environmental analysis. For both non-competitive leases and competitive leases there will be an initial NEPA review during the issuance of a lease or lease sale and based on a site assessment plan. After the 5 year site assessment plan, lessees will be required to submit a construction and operations plan triggering a second NEPA review. Finally, two years before the end of the lease, the lessee must submit a decommissioning plan, which will again trigger a NEPA review (USDOI, MMS, 2009).

For commercial leases, BOEMRE will conduct a site specific EIS before allowing activities to commence. It is possible that in the future EAs may be more widely used for NEPA compliance (USDOI, MMS, 2009).

9.4.4. Operation

BOEMRE will take an adaptive management approach to regulation and will allow operators to validate their own performance. BOEMRE will require developers submit detailed safety and environmental monitoring plans and self-report on their compliance annually. BOEMRE will request that developers submit data on air quality, monitor the incidental take of threatened and endangered species and marine mammals, demonstrate the training of personnel, and conduct annual facility inspections to ensure compliance with to be developed standards. BOEMRE will also require operators to submit incident reports in the event of injuries or damage to facilities. BOEMRE will conduct both scheduled and unscheduled inspections of facilities to ensure compliance (USDOI, MMS, 2009).

9.4.5. Decommissioning

BOEMRE has recognized that large scale decommissioning will not occur for several decades and may change regulations to reflect future technological changes. Operators will have to furnish a surety bond for decommissioning. The size of the bond will be determined on a case-by-case basis. Operators will also have to submit a decommissioning plan 2 years before the end of the lease and must complete decommissioning within 2 years of the end of the lease. Operators will have to remove all structures to a depth of 15 feet below the mud line, similar to the requirement for oil and gas structures and wellbores. BOEMRE may authorize facilities remain in place on a case-by-case basis (USDOI, MMS, 2009).

9.4.6. Supplemental Bonding

Supplemental bonds are required in the GOM for leases that do not meet a minimum financial threshold. For offshore wind operations, it is conceivable that the Federal Government will require financial assurance to ensure that structure removal and site clearance operations will be performed in the event the operator goes bankrupt. For oil and gas structures that are transformed into an offshore wind site, the supplemental bond will be similar to existing requirements as described in Kaiser and Pulsipher (2008) except that P&A requirements will likely have already been performed.

9.5. Regulatory Issues

9.5.1. Lease Terms

Length of Lease

In order for a regulatory system to allow for development to occur, the length of the lease must be long enough for companies to recoup their initial investment, which, in the case of offshore wind power, can be quite high. Lease durations of 30 to 50 years are generally preferred by industry (AWEA, 2006; Hobson, 2006) and are being used in the UK. A lender is unlikely to allow for a loan to be financed for a term longer than the term of a lease. Therefore, long leases allow developers to finance loans over longer periods, reducing annual payments. In addition, long leases allow developers to delay decommissioning as long as possible. The technologies and regulatory options available for decommissioning may change as the first wind farms are removed and it is possible that the costs of decommissioning may fall as learning occurs, but the use of marine vessels will always induce a fixed cost of the operation.

There are costs associated with long leases. Over the next 30 to 50 years there may be significant changes in the electricity industry in the U.S. due to climate change, changing environmental regulations, and depletion of oil and natural gas. The effects of these changes are difficult to predict, but it is plausible that the profitability of renewable energy generation could increase dramatically in the coming decades. If this were to occur, then private companies could be making very large profits from the use of public lands and may be paying only very low rental fees or royalties to the federal government due to the lease conditions that were determined when the economics of offshore wind farms were very different. Even leases in which royalties are based on gross revenue may have this problem. In this case, even though the government's roylaties would increase as the profit of the developer increased, the public may demand a higher proportion of revenue from a highly profitable enterprise than they would from a barely profitable enterprise.

Long leases also do not allow for repowering. If a company repowers a wind farm it might have to shutdown turbines, which would induce a minimum royalty payment to the landowner. It is also likely that repowering would be expensive. For example, if a lease was for 30 years and repowering would be expected to occur after 20 years, then a company may decide that it would not be able to recoup the costs of repowering over the remaining 10 years of the lease.

Long leases will raise surety bonding requirements. In general, surety bonds are short term instruments which require the insurer to estimate the financial viability of a company over 2 to 5 years. In the oil and gas industry, surety bonds can be longer which increases the risk to insurers and the insurance premium and decreases the number of companies capable of insuring these projects. In the offshore wind industry, it would be very difficult for underwriters to project the financial viability of a company over a period of 3 to 5 decades; as a result, we would expect collateral requirements to be very high.

Clauses which allow for the renegotiation of specific terms under specific circumstances may help to deal with some of these issues. For example, regulators could insert clauses into leases that allow for renegotiation of royalty rates if the price of a kWh (and associated renewable energy credits) exceeds some threshold (perhaps 25 cents, adjusted for inflation). Similarly, regulators could allow for renegotiation if the developer could demonstrate that by repowering the site they could increase electrical output by some percentage.

Lease Fees

Low lease fees that encourage development have been supported in the U.S. by both industry and environmental groups (Coequyt, 2006; Cousins, 2006; Evans, 2006; Heimann, 2006; Hobson, 2006; Kennedy and Chasis, 2006; Pope, 2006; Quaranta, 2006). In Europe, lease fees are either non-existent, or overwhelmed by government subsidies. In Texas, royalties are more significant, up to 5.5 percent of gross revenue.

Lease fees include royalties and rental fees. Generally, royalties are used when one party owns something and allows another party to profit from its use. For example, in the oil and gas industry, the federal government owns the oil and allows a private company to extract it, with a royalty paid to the federal government. In the case of offshore wind, royalties may not be appropriate since the federal government does not own the wind. Instead, the public owns the land that wind turbines would use, thus, rental fees may be more appropriate.

However, in structuring a lease agreement it may be preferable to use royalties over rental fees. The use of low rental fees and higher royalty rates could allow for companies to pay lower upfront costs during resource assessment and construction phases and then to pay higher costs once the project begins generating power, and thus, revenue. Royalties may also ensure that the public benefits from the use of a public resource. If the value of renewably generated electricity increases, land rents would not capture this increase but a royalty on gross revenue could.

In deciding the proper rate for lease fees, regulators must decide what these lease fees are designed to collect. Should they collect the administrative costs, the opportunity costs or forgone competing uses, or the maximum public monetary benefit? If they are designed to cover only administrative costs then the leasing fees could be quite low. Similarly, since offshore wind projects should not exclude most other uses of the area (i.e. commercial fishing, recreational fishing and boating, other alternative energy uses), the opportunity costs might also be low (Cousins, 2006). The primary opportunity costs lost would be from sand and gravel mining and trawling, which may or may not occur on the site. Conversely, if fees are designed to collect the maximum monetary benefit the fees would be limited only by the competitive process and the profitability of the projects.

Lease fees may or may not be balanced against already existing tax credits and other subsidies for renewable energy. The federal Production Tax Credit (PTC) gives producers of renewably generated electricity a tax credit of 2 ¢/kWh over the first 10 years of generation. For comparison, the BLM charges about 0.09 ¢/kWh. Similarly almost all of the states that may eventually produce offshore wind energy (the exceptions being Louisiana, Virginia, Georgia, and Michigan) have Renewable Portfolio Standards which create a market for renewable energy certificates. It would seem to make little sense for the government to financially encourage wind energy with tax credits and renewable energy mandates, while at the same time collecting large rental fees. However, the BOEMRE has argued that these financial incentives are designed by Congress to represent the value of the societal benefit from renewable energy production (*Federal Register*, 2008a). By this logic, regulators need not concern themselves with the societal benefit of offshore wind power and only need to consider the fair return to the public for the use of public land.

Finally, it is important to note that at this stage of development, lease fees can stymie development, but they cannot truly stimulate it. A high fee (5 percent) of gross income could potentially hinder development, but the converse is not equally true. Even if lease fees are so small as to be negligible, it is the underlying economics of offshore wind farms that will determine if they are built. Of course, low lease fees will cause developments to be more profitable and allow for development in areas that higher lease fees might foreclose, but only a subsidy of several cents per kWh would change the underlying economics of offshore wind farms and truly stimulate the industry.

Timelines for Development

Low lease fees could also retard development. If lease fees or rental rates are low enough that a company could cheaply secure rights to an area and thereby exclude competitors, then companies may attempt to rent large portions of land without the intent of ever developing them. Winergy has been accused of this (Kaplan, 2004). As a result, most leases have inserted timelines for development with developers having a specified amount of time (usually 3 to 5 years) to begin construction and operation.

Strict timelines could force a developer to begin construction when market conditions are not favorable. The cost of construction and turbines are the largest costs facing offshore wind development. These costs are dependent on steel prices and vessel rates which can be volatile. Thus, strict timelines might force a developer to begin construction at a time when the costs of construction are temporarily high, endangering the financial viability of the project.

Phased Access

Leases usually grant some type of phased access in which the lessee has a short term right to evaluate a wind resource with the option for a longer term right to develop that wind resource. Phased access allows developers to reliably estimate the wind resource at a site, thereby estimating cash flow and removing a degree of uncertainty from their development decision. Phased access is widely supported by developers (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006). Phased access that does not include a preferential right for the developer doing the resource assessment to exploit the resource may stymie development. Resource assessments may be expensive and a company may be unlikely to enter into a lease allowing them access to an area for resource assessments if they are not granted the right to develop the resource. The only system in which there is no real phased access is in Denmark, where the government selects sites and conducts preliminary studies that essentially mirror the early phases of developer access elsewhere.

Regulators must also decide if they should allow leases for pilot projects that might follow different rules than large scale projects. For example, regulators could allow projects below a specific capacity to be processed on an expedited basis using less stringent environmental review (Firestone et al., 2004).

Project Criteria

When conducting a competitive lease, the government can either specify the generating capacity of the planned development (as in Texas and Denmark) or they could allow developers to submit their own plans for the land to be leased. Allowing developers to decide the capacity of the proposed projects could give large developers an advantage over smaller developers. For example, a large developer may be able to reasonably propose a 300 MW development on a given area while a smaller developer or municipality may only be able to raise the capital for a 150 MW development. The larger development would provide more revenue to the government, and would be favored in any approval system based on wholly or partially on the financial benefit to the public. BOEMRE has proposed to address this issue by comparing plans based on their per MW or per acre benefit to the government.

9.5.2. Competition and Approval Criteria

Competition

There are two main models for awarding leases. Regulators could either select sites (often with developer input) and hold a competitive process, or they could allow developers to select sites. If developers select sites, competition could be enhanced if they were presented with deadlines and regulations for the minimum distance to other wind farms, as in the UK. Deadlines would keep developers from rushing to be the first to submit a proposal rather than the best (as in Germany), while minimum distance requirements (for example 10 km) would help to define when two proposals were actually competing.

If regulators select sites, competition could be simplified if they also set guidelines for development, especially the size of development, as in Denmark. This would make comparisons of alternative projects simpler; however, if the guidelines were too detailed, it might also restrict creativity. Regulators selecting sites would also ensure that development occurred at a measured pace, much as it has in Denmark.

If a regulator decides to select sites, it may take several additional years for offshore wind projects to commence while the regulator conducts detailed studies. One option would be to follow the British example and to conduct leasing in two phases. The first phase would be developer driven in which developers would have to submit proposals for specific sites by a specific date. While this first phase was ongoing, regulators could identify potential suitable areas, begin the environmental review process and conduct a leasing competition similar to those it conducts for oil and gas leasing. In the long term, by beginning the environmental review process before competition, regulators might speed development.

Approval Criteria

The degree of competition will in part decide the criteria by which proposals will be judged. If there is no competition then proposals may be judged on technical and economic feasibility, profitability and environmental impacts. If there is competition, then an additional criteria of compensation to the government may be added.

The use of profitability as an approval criteria has costs and benefits (Heimann, 2006; Pope, 2006). Its use would lower the possibility that developers would go bankrupt and therefore be unable to remove wind turbines and foundations, an important consideration for regulators. However, industry groups have argued that it would be difficult for regulators to accurately predict the economic return of an offshore wind project to a company and that private companies already have oversight of their financial decisions from investors and shareholders (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006).

The use of a profitability standard may retard development in the short term but might encourage development in the long term. Determining the profitability of a proposal would likely take a significant amount of time and resources; however, if regulators intend to establish a successful long-term leasing program, ensuring that the programs that are built remain profitable and operational is important.

9.5.3. Environmental Analyses

The National Environmental Policy Act (NEPA) requires that the federal government consider the environmental impacts of all of its decisions. Similar laws apply in Europe. The most complete form of environmental analysis under NEPA is the EIS, a document which can take years to complete. Alternatively, NEPA allows for shorter EAs if significant environmental effects are unlikely, or CXs if actions do not have significant environmental affects. BOEMRE could require site specific EISs for every offshore wind power development, as favored by environmental organizations (Coequyt, 2006; Pope, 2006). This may be appropriate given the scope and nature of offshore wind energy (Kellerman et al., 2006; Öhman et al., 2007). Alternatively, BOEMRE could conduct a programmatic EIS for offshore wind power (it has already conducted a PEIS for alternative energy use in general) (USDOI, MMS, 2008c) and use EAs and CXs, as favored by some representatives of industry (Hobson, 2006). Site specific EISs will slow development compared to CXs and EAs, but will ensure NEPA compliance and will ensure that the environmental impacts of a specific project at a specific site are considered. Given that there has been local opposition to proposed wind farm development in the U.S. (i.e. Citizens to Protect Nantucket Sound), it seems plausible that a BOEMRE decision to issue a CX could be challenged in court (Brown and Escobar, 2007). Also, the environmental impacts of an offshore wind farm are likely to be site specific. A final compromise option would be for BOEMRE to develop a PEIS for offshore wind and allow site specific EISs to branch off of the PEIS.

If regulators require site specific EIS (or their equivalent) for all offshore wind projects, there is an additional decision regarding the amount of data to require. Regulators could issue blanket guidelines for data or could allow data requirements to be developed for each EIS. Blanket data requirements will likely slow development unless they are so minimal as to be largely meaningless. The US Fish and Wildlife Service has argued that three years of avian radar data be collected for each EIS (Bennett, 2006).

9.5.4. Operational Issues

Regulators must decide how to monitor the operation of offshore wind farms including environmental compliance and worker safety. Regulators must first decide who should conduct the required monitoring. The government, developers, or a third party could conduct the required monitoring. There is a clear conflict of interest if developers are allowed to conduct their own compliance monitoring, but this is likely to be the cheapest option and it is favored by developers (AWEA, 2006; Cousins, 2006; Hobson, 2006; Quaranta, 2006). Third party monitoring is likely to be more expensive, and government monitoring would require regulators to develop new institutional skills.

The methods for conducting environmental monitoring are also important. Adaptive management, in which a project is monitored for its environmental impact and project parameters are changed as issues are identified, is a widely used method for natural resources management (Holling, 1978). However, adaptive management requires both reliable data, and an ability to adjust operating parameters if an issue is detected. In the offshore wind farm environment it can be difficult to monitor environmental effects. Wind farms are spread over tens of square miles and dead animals will often disappear into the sea. Full-time onsite personnel, while expensive, may be required if adaptive management is to be successful. To date, none of the offshore wind farm installations are manned, but Horns Rev II is expected to be the first manned offshore wind farm. Furthermore, if an unforeseen problem arises it is not clear what mitigation measures could be taken. These mitigation measures would need to be explicitly identified in the lease. The alternative to adaptive management, a regulatory scheme in which all research is done prior to construction and all of the relevant issues are identified and optimal policies chosen before operation, may not be plausible in the case of offshore wind farms due to the fact that offshore wind farms are so novel and so much remains unknown about their operation and interaction with the environment.

Worker safety is vitally important for offshore wind farms, but has not been seriously addressed by regulators. Since the wind industry began in the 1970's at least 33 people have been killed installing and servicing wind turbines (Gipe, 2007). Most of these deaths have been caused by either falls, entanglement in the internal machinery of the nacelle, or vehicle accidents during transport. These deaths have resulted from worker error and equipment malfunctions. The offshore wind industry will share all of the dangers of the onshore industry and will have additional hazards. Like the onshore industry, maintenance on offshore turbines will require workers to regularly climb to the nacelles of turbines, several hundred feet above the surface. However, the offshore industry raises the additional hazard of gaining access to the turbine. Access can be through either boats or helicopters. Moving personnel and equipment from boats onto a boat landing on turbine tower could be hazardous, even in moderate seas. As a result, there is interest in developing stable catamarans with specially designed bows to facilitate safe movement. In the offshore oil industry a great deal of personnel movement is carried out by helicopter; however, in the offshore wind industry this involves helicopters hovering nearby turbine blades which is dangerous, although this is done in limited circumstances.

Power purchase agreements (PPAs) are another important consideration for regulators. PPAs are contracts between an electricity producer and the utility that operates the grid and provide a stable price for both parties over a long term. Without a PPA, a wind farm would have to sell its electricity on the spot market. Currently, offshore wind leases do not contain clauses forcing developers to obtain PPAs, although they could potentially reduce the risk of bankruptcy.

9.5.5. Decommissioning

Regulators have given minimal attention to decommissioning. In the BOEMRE Cape Wind Draft EIS, a 718 page document, just a page and a half was dedicated to decommissioning. Likewise, the UK did not develop decommissioning guidelines until years after their first offshore wind farms were operational.

Bonding Methods

There are a number of options for ensuring decommissioning. Surety bonds, letters of credit and escrow accounts could all be used to ensure that the funds required for decommissioning are available at the end of the lease or if the company goes bankrupt (Kaiser and Pulsipher, 2008). An irrevocable letter of credit and a surety bond ensure that funds are available regardless of the financial standing of the developer. Depending on the terms of the escrow account, it may or may not ensure that the necessary funds are available throughout the lease since some escrow accounts do not require the full amount needed for decommissioning be deposited until several years after the start of operations.

Studies of alternative methods of decommissioning compliance in the oil and natural gas industry have indicated that surety bonds afford regulators with a high degree of certainty that the site will be decommissioned according to agency requirements, and do so with relatively low costs to either the government or the developer (Ferreira et al., 2004; Ferreira and Suslick, 2001). Not surprisingly, almost all bonds in the offshore oil and gas industry are surety bonds; it is reasonable to expect that most offshore wind structures will be bonded with surety bonds.

Decommissioning Options

In the oil and gas industry every structure must eventually be removed. However in the offshore wind industry the wind resource is inexhaustible, so decommissioning will only need to occur in the case of bankruptcy, unprofitability, or if there are no repowering options available. At the end of a lease the lessee may have one of several desires. The lessee may want to repower the site, the lessee may want to keep the site in production, but not repower it (perhaps in order to forestall paying decommissioning costs), or the lessee may want to abandon the site. Regulators, in turn, have several options. If the lessee wants to repower the facility or otherwise keep it in production, they could either renegotiate or terminate the lease. If the lessee chooses to terminate the lease, regulators could either force the lessee to decommission the site or they could allow for an agreement in which a new third party takes over the lease site. Presumably, the new third party would inherit ownership of the turbine structures and transmission facilities and the liability for their removal. Under current oil and gas law, the previous owner is still liable for decommissioning if the new owner declares bankruptcy.

In the case of bankruptcy, the liability for structure removal could eventually fall to the government (depending on if the site transfers ownership or is inherited by creditors). If the government becomes responsible for the site, it could either decommission the site using a surety bond, or it could auction off the rights to operate the site.

Regulators must also decide whether or not to allow the use of offshore wind foundations as artificial reefs. Monopiles and gravity foundations lack the structural complexity of jacketed foundations and may be less productive as artificial reefs, but studies at two wind farms in Sweden have shown greater diversity of fish and greater numbers of blue mussels were found near monopile foundations than in control sites (Wilhelmsson et al., 2006).

Decommissioning Costs

If the government decides to decommission the site, it must ensure that the size of the bond covers removal costs. Importantly, there are no published studies on the appropriate value of these bonds for offshore wind facilities and there are reasons why bond values from the offshore oil industry may not be appropriate for the wind industry. First, anywhere from 25 to 50 percent of the costs of decommissioning oil and gas structures stem from the costs of plugging and abandoning wells which will not occur in offshore wind decommissioning (Kaiser et al., 2003). Secondly, oil platforms are usually 4 or 8 piled structures, whereas wind foundations are usually single piled, similar to caisons, although foundations in deeper water may have 3 or 4 piles. Offshore wind farms are also not likely to be in water as deep as oil and gas platforms for the next decade or so.

Studies of decommissioning costs of oil and gas structures in the Gulf of Mexico suggest that the average cost for removing a 4 piled structure, discounting plugging and abandonment and pipeline abandonment operations, is $664,000. These data were from structures decommissioned between 1991 and 2001; adjusting for inflation and assuming a normal distribution of costs and years, the cost in 2008 would be $926,000. The cost for an 8 piled structure is approximately 1.5 times that of a 4 piled structure, thus, it would not be appropriate to assume that a 1-piled structure would cost one-fourth of a 4-piled structure. Instead, a 1-piled structure might cost 33 to 50 percent of a four piled structure or $305,000 to $463,000. A wind farm might be composed of 100 or more turbines, but due to economies of scale, it is unlikely that the decommissioning costs will scale linearly. Thus, a 100 turbine wind farm should cost less than $50 million to decommission.

Importantly, $50 to $60 million in liabilities is the maximum amount that the U.S. offshore oil and gas plugging and abandonment surety bond market can underwrite. One of the two major companies in this industry, RLI, has expressed some interest in the offshore wind market and may be willing to underwrite some projects. However, the surety bond market is extremely risk averse and they may require large amounts of collateral before issuing a bond.

9.6. Conclusion

A number of commentators have concluded that the preferred way for nations to regulate the offshore wind industry is to set up a "one-stop shop" (as in Denmark) approach in which permitting authority is consolidated into a single governmental agency (Firestone et al., 2004; Peloso, 2006; EWEA, 2007). In our review, we found no evidence that a one-stop shop would in fact speed development. Given the large amounts of time, capital and planning involved with the development of an offshore wind farm, it seems unlikely that the requirement to seek permits from numerous governmental agencies is a significant administrative burden on applicants. Both the BOEMRE oil and gas leasing program and the UK offshore wind programs have been successful despite requiring permitting and consultation from a variety of government agencies.

Instead, we find few relationships between regulatory techniques and successful installations. We do note the lack of development in Germany, and to a lesser extent the Netherlands, and question whether that is associated with a regulatory system that rewards first, rather than best, applicants. While over-regulation, especially through high fees, may be able to handicap the offshore wind industry, regulators are unlikely to be able to actually stimulate the offshore wind industry. The industry will experience rapid growth only when technological development, cost reductions from learning and government subsidies allow it to compete in the market.

As important or more important for the development of offshore wind power are the subsidies that federal and state governments authorize for renewable energy in general and offshore wind power more specifically (Bird et al., 2005; Reiche and Bechberger, 2004). It would be easy to ascribe the success of Denmark and the UK to convenient regulations, but it is far more likely that a mix of financial subsidies and amenable offshore sites has led to the development of the offshore wind industry in these countries.

10. COMMENTARY ON THE USE OF OFFSHORE OIL AND GAS INFRASTRUCTURE IN WIND ENERGY APPLICATIONS

Platform removal represents a liability for the oil and gas industry and there has been interest in alternative options to removal for many years. One recently discussed alternative is to place wind turbines on oil and gas structures after production ceases either for wind farm development or for enhanced oil recovery. In this final chapter, we discuss the benefits of these plans, the difficulties with their implementation and the alternative possibilities for synergy between the offshore oil and gas and wind industries.

10.1. Introduction

There are two options for the use of oil and gas infrastructure in the offshore wind industry. The first option is to place wind turbines on platforms without removing the platform from its current location. The second option is to remove platforms from their current location and to reuse them as foundations for wind turbines. There are costs and benefits associated with both of these options; however, neither option is particularly attractive or likely to provide a market for many offshore structures.

At least two companies, WEST and Talisman Energy, have investigated the potential for using oil and gas infrastructure in the offshore wind industry. Talisman Energy has been actively investigating the possibilities of using the infrastructure of the Beatrice oil platform for offshore wind power. In 2006 and 2007, Talisman installed 2, 5 MW turbines in 45 m of water 1.6 and 2.3 km away from their Beatrice platform in the Scottish North Sea. The turbines were placed on jacketed foundations, and anchored to the seafloor with piles. The two turbines are linked to each other and the main platform with a 33 kV underwater electrical cable and can supply about 33 percent of the platform's electrical consumption (Eaton, 2008). The platform is also connected to the Scottish grid. Talisman developed this site as a 5 year test facility for a much larger, 1 GW development which would utilize the current Beatrice infrastructure for electrical service platforms, crew quarters and electrical transmission.

Talisman estimated the energy costs at Beatrice to be about $15 million in 2006. The Beatrice project cost $90 million (Eaton, 2008). Whether the wind turbines pay for themselves through reduced fuel costs will depend primarily on the future price of energy and the discount rate used to finance the project.

In the U.S., the Louisiana-based Wind Energy Systems Technology has also been investigating the potential use of oil and gas structures for offshore wind farms. They are in the late planning stages for an offshore wind farm off the coast of Galveston, Texas and have spent several years considering how to efficiently take advantage of the infrastructural resources of the GOM (Schellstede, 2008). They have decided that the GOM has a number of infrastructural advantages that make it appropriate for the development of offshore wind energy; however, these advantages are mostly associated with the skills and experiences of the people working in the offshore oil and gas industry rather than the physical infrastructure in the GOM.

10.2. Benefits

The use of offshore oil structures as wind foundations has benefits for both the oil operator and the wind developer. For the oil operator, the benefit would be the ability to sell a structure for more than the scrap value and avoiding or deferring decommissioning costs. For the wind farm developer, the primary benefits are through reducing foundation costs and reduced environmental impacts.

10.2.1. Delaying Decommissioning Costs

For the oil industry, one of the biggest benefits of placing wind turbines on oil and gas structures is the ability to defer decommissioning costs. Since present costs are discounted relative to future costs, this would save oil operators money. Of course, this would only be possible if the structures were not going to be moved to another location. Decommissioning costs are highly variable and are a function of the size of the structure and its depth. On average, removal costs for a single-piled caisson structure in under 100 ft of water is $500,000. For a fixed platform, the cost is $875,000 (Kaiser et al., 2003). Thus, by converting an oil and gas structure to wind use, an offshore operator may be able to defer over $500,000 in costs, or pass these costs along to a new owner.[26]

10.2.2. Foundation Costs

For wind power developers, decreasing the costs of foundations is a major benefit of using platform foundations for wind turbines. Foundation costs are a large proportion of the total costs of offshore wind power. Foundations, including installation, are estimated to represent about 20 percent of the capital costs of offshore wind farms (Morgan et al., 2003; ODE, 2007) and 10 to 20 percent of the cost of energy (Musial et al., 2006; Dept. for Business Enterprise and Regulatory Reform, 2004). In general a used foundation in the GOM will sell for about 30 to 50 percent of its original fabrication costs (Byrd, 1998). Thus, by using a previously constructed foundation over a new foundation, developers may be able to save 10 percent on total capital costs. These costs assume that the foundation is brought to shore; if the wind operator were to use a foundation in place, the cost savings could be greater.

10.2.3. Marine Habitat

Offshore oil and gas structures serve as artificial reefs and provide habitat for marine organisms (Kasprazk, 1998). The removal of these structures removes this habitat. In some cases, offshore oil and gas platforms are toppled in place or moved to nearby locations to serve as artificial reefs; however, the removal of these platforms has environmental impacts, which could be delayed by using platforms as foundations for wind turbines. Furthermore, by placing a wind turbine on a structure already in the GOM, the environmental impacts of wind farm could be reduced since piling operations would not be needed.

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[26] Importantly, decommissioning obligations can never be entirely avoided. Even if a structure is passed to a new owner, the government can seek to recover decommissioning costs from the original owner if the new owner is unable to pay these costs (*Federal Register*, 2008a).

10.2.4. Visual Benefits

One of the primary objections to offshore wind power has been that it presents a visual dis-amenity to nearby landowners. However, it is likely that offshore wind turbines would present a visual amenity when compared to offshore oil and gas platforms. In the U.S., oil and gas platforms can be seen from the coasts of several Gulf States, including some beaches used for vacation and recreation, for example, Gulf Shores, Alabama. If residents and visitors viewed offshore wind turbines more favorably than offshore oil and gas structures, then the replacement of oil platforms with wind turbines could act as a visual amenity and could potentially lead to an increase in tourism.

10.3. Difficulties

10.3.1. Economies of Scale

One of the biggest difficulties in using oil platforms for wind energy is in the economies of scale. The cost per kWh of offshore wind energy decreases with increasing sizes of development (Barthalemie and Pryor, 2001). In part, this is due to lower prices for large turbine orders; for orders of hundreds of turbines, the actual price can be up to 55 percent below the list price (Junginger et al., 2005). Therefore, developments need to be composed of dozens or hundreds of identical wind turbines. Offshore wind developers intending to use foundations from the offshore oil and gas industry would need to find dozens of similar foundations. Since foundations in the oil and gas industry are custom made for a specific purpose and site, and since platforms are decommissioned and either reused or sold as scrap as they reach the end of their economically useful life, this could be difficult.

10.3.2. Location

While the GOM does have some sites that may be amenable to offshore wind power, in general the winds off Texas, Louisiana, Mississippi and Alabama are not as powerful as those in other parts of the country, especially the northeast (Archer and Jacobsen, 2005; USDOE, NREL, 2008). Similarly, electricity rates in the southern U.S. and renewable energy policies in these states are not amenable for new and expensive renewable energy development. Of the GOM states, only Texas has a Renewable Portfolio Standard (DSIRE, 2008), and only Texas has an average retail electricity price of over 10 cents per kWh (USDOE, EIA, 2008). Thus, the GOM in general is not at present a particularly attractive market for offshore wind energy.

The location of platforms within the GOM is important. The amount of wind energy available to a turbine scales with the square of wind speed. As a result, wind turbines need to be placed in high wind areas in order to generate as much electricity as possible. Thus, it is not likely that the placement of oil and gas platforms will be suitable for wind turbines; and while there are areas of the GOM that may be appropriate for wind use, most areas need further resource assessment.

Additionally, turbines need to transmit generated electricity to shore; this becomes more difficult and expensive as the distance to shore increases. Consequently, most offshore wind farms have been located less than 10 miles from shore and offshore oil and gas foundations far from shore would not be useful for wind energy generation. As a result of these constraints, it would be difficult for developers to use offshore oil and gas infrastructure for wind energy applications without removing the platforms and transporting them to a new location.

10.3.3. Configuration

Wind turbines need to be precisely positioned within the wind farm. Wind turbines need to be separated from each other, usually by 500 to 1,000 m, in a grid arrangement to reduce wake effects and to minimize cabling layout. Existing oil and gas infrastructure is not suited to this requirement. Thus, the only real option available to wind developers seeking to use the oil and gas infrastructure of the GOM would be to collect dozens of similar jacketed foundations and to move them to a new site. It is unlikely that a developer would be able to find these foundations as operating structures and be able to wait for them to be decommissioned; instead, a developer would have to collect and store these foundations among previously decommissioned structures. This has proven impractical for WEST (Schellstede, 2008).

10.3.4. Engineering Requirements

In most cases the 4-piled oil and gas foundations are not the most efficient foundation for an offshore wind turbine in shallow water. In the shallow waters of the North Sea, monopiles and gravity foundations have been used much more frequently than jacketed foundations. Jacketed foundations generally require four piles to be driven per foundation, while monopiles require only one pile driving operation per turbine and gravity foundations do not require pile driving. These additional piling operations would add economic and ecological costs to an offshore wind farm which would have to be balanced by the saved costs of the recycled foundations.

It is also important to note that not all offshore oil and gas structures are amenable to the placement of offshore wind turbines. Offshore oil and gas structures are designed to handle significant vertical weights; however, they are not designed to handle the kinds of horizontal forces that an offshore wind turbine is subject to. The foundations for offshore wind turbines must be engineered to withstand powerful winds acting on three-60 m long blades and a 100 m high steel tubular pole. While many oil and gas structures may be able to handle these forces, their ability to do so must be analyzed on a case-by-case basis.

Additionally, some oil and gas structures in the GOM are over 60 years old and many more are 40 to 50 years old. While oil and gas structures are generally designed for 100 year lifetimes, a platform built decades ago would require significant inspection and upgrade before it could be used as a foundation for a wind turbine.

10.4. Alternative Offshore Uses

10.4.1. Intra-Field Use

Another possibility is to use unused oil and gas platforms as foundations for wind turbines and to transfer the electricity to other nearby oil and gas platforms. This has a number of potential advantages but has not been well studied. First, it would allow for wind turbines to be placed far offshore, where wind speeds are generally higher, but would reduce the need for long distance transmission. This would eliminate the need for high-voltage transmission and thus offshore electrical service platforms. Second, it would allow wind power to compete not with coal fired electricity, but with the diesel fuel or natural gas that normally powers offshore oil and gas platforms. Finally, it might provide enough cheap electricity to make enhanced oil recovery economically feasible in the GOM.

Since wind is not constant, wind energy could not replace diesel or natural gas fired electricity on offshore platforms, but could only supplement it. Thus, offshore platforms would still need generators and associated infrastructure and the only savings would be in a reduced consumption of fuel.

The feasibility of using existing oil and gas structures for electricity generation for nearby oil and gas platforms will depend on a variety of factors. In general, diesel powered platforms far from shore will be more amenable to offshore wind usage than natural gas powered platforms and those close to shore. This is because as distance to shore increases the transport costs of fuel and the wind speed increase, making wind power more profitable. Wind turbines require large up-front costs which take years of profitable operation to recover. Thus, only structures and leases with at least 15 to 20 years of future life could be expected to be economically converted to wind usage. Again, these structures are most likely to be the newest structures in the deep water furthest from shore. However, the structures far from shore in deep water are at lower densities than those closer to shore; thus it is unlikely that there will be a nearby inactive structure to act as a foundation.

10.4.2. Small Scale Use

Despite the problems of economies of scale, there have been and continue to be small community based projects of a few offshore turbines generating electricity for a locally owned cooperative. Examples are in Samso, Denmark and Hull, Massachusetts (Manwell, 2007). Thus, it is reasonable to think that a community could purchase or lease a small number of nearby oil and gas platforms and place wind turbines on them. However, the oil and gas platforms located close to shore in the GOM are primarily off coastal Louisiana, an area with small population densities and covered by swamps and other environmentally sensitive areas. It is reasonable to think that the costs, both economic and ecological, of laying transmission cables in this area would be significant. Furthermore, these areas have low population densities and high levels of poverty and it is unlikely that these communities would be as willing or able to finance offshore wind power projects as those in Massachusetts or Denmark.

10.4.3. Electrical Service Platforms

Oil and gas platforms could be relatively easily used as foundations for electrical service platforms (ESP) for offshore wind farms. ESPs are present at almost all offshore wind farms and are used to increase the voltage from approximately 33 kV among the inter-turbine electrical grid to over 100 kV for transport to shore (Ackermann, 2005). From an engineering standpoint, ESPs are similar to oil and gas platforms in that they are heavy and compact and subject to lower horizontal loads than wind turbines. WEST is planning on using a recycled jacketed platform for this purpose (Schellstede, 2008). As wind farms grow in size and reach further offshore, DC transmission will become more attractive. DC transmission requires a significant amount of space for conversion from AC to DC, thus, large jacketed structures used in the oil and gas industry may become increasingly useful for offshore wind farms.

10.4.4. Electrically Connected Platforms

In the GOM, offshore platforms are powered by diesel fuel or natural gas and are not connected to the onshore electrical grid. In Europe, however, some offshore production facilities are linked by electrical transmission cables to the mainland. Offshore wind farms could use this existing infrastructure. In this case, a developer could conceivably have to pay neither transmission nor foundation costs; this would total a 30 to 35 percent reduction in capital costs.

10.4.5. Resource Evaluation or Technology Testing

Resource evaluation, including the long term measurement of wind speeds at the hub height of proposed turbines is an important component of planning and developing an offshore wind farm. Existing offshore oil platforms may be well suited to this task, and indeed several structures in the GOM collect a wide variety of wind related data (Kaiser and Pulsipher, 2007b). In this case, large numbers of foundations are not needed, the platforms do not need to be electrically connected to the mainland, and the engineering requirements for placing 60 m high anemometer masts are not as significant as the requirements for placing an entire turbine at an equivalent height. Thus, it is plausible that oil and gas foundations could serve as platforms for resource evaluation. Similarly, technology testing is expected to become an important part of the future ocean energy industry. Wind energy developers may seek to test new turbine concepts, or current or wave energy developers may seek to test new energy conversion technologies. Again, oil and gas structures may provide a convenient platform for these activities.

10.5. Factors Influencing Utilization

There are a number of factors that make reusing oil and gas infrastructure for offshore wind power impractical; however, changes in some of these factors may make it more likely that wind developers would seek to use GOM infrastructure for offshore wind projects. If the costs of wind turbines decreases and the value of renewable energy increases, perhaps due to greenhouse gas legislation, then it is possible that developers could ignore issues of scale and could place wind turbines on the small number of available appropriate structures. It seems likely that the value of renewable energy will increase due to legislation; however, the cost of wind turbines has also been rising in recent years due to climbing demand.

If the offshore wind industry develops to a point in which shallow sites have already been developed, or are found to be ineligible for development for environmental or aesthetic reasons, then developers may be drawn to deeper waters. The jacketed structures used in the oil and gas industry are well suited to these waters while the traditional foundation techniques used in the oil and gas industry, monopiles and gravity foundations, are not. This might make the re-use of oil and gas infrastructure more practical since jacketed structures would not have to compete with gravity or monopile foundations.

10.6. Conclusion

It is possible that a few of the oil and gas platforms decommissioned in the GOM could be used as either ESPs in offshore wind farms or as bases for wind turbines for intra-oil field electrical generation or for test platforms for resource evaluation. It seems unlikely that large numbers of platforms will be used for these purposes. It is possible that a developer could collect a number of similar jacketed structures and relocate them for use in an offshore wind farm; however, this has so far proven impractical. If an offshore wind industry does develop in the GOM, it seems most likely that the decommissioned oil and gas infrastructure will serve as a source of steel. In sum then, the use of oil and gas infrastructure for offshore wind farms may provide a local market for scrap steel, but it is very unlikely that large numbers of oil and gas platforms will become foundations for offshore wind turbines.

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GLOSSARY OF ABBREVIATIONS

COE-Army Corps of Engineers

BERR-UK Department of Business, Enterprise and Regulatory Reform

BLM-Bureau of Land Management

BOEMRE-Bureau of Ocean Energy Management, Regulation and Enforcement

BSH- German Federal Maritime Agency

CE-Cost of Energy

CX-Categorical Exclusion

DEA-Danish Energy Authority

DOE- U.S. Department of Energy

DTI-UK Department of Trade and Industry

EIS-Environmental Impact Statement

FCR-Feed Conversion Rate

GIS-Geographic Information System

GLO-Texas General Land Office

GMIT-Gulf Marine Institute of Technology

GOM-Gulf of Mexico

IPCC-Intergovernmental Panel on Climate Change

LARP- Louisiana Artificial Reef Program

LIOWP-Long Island Offshore Wind Park

MFA-Marine and Fisheries Agency

MMS-Minerals Management Service

NOAA-National Ocean and Atmospheric Administration

NPV-Net Present Value

NREL-National Renewable Energy Laboratory

OAC-Gulf of Mexico Offshore Aquaculture Consortium

OCS-Outer Continental Shelf

OOA-Open Ocean Aquaculture

PTC-Production Tax Credit

P&A-Plug and Abandon

NEFA-National Fisheries Enhancement Act

NEPA-National Environmental Policy Act

REC- Renewable Energy Credit

RHA-Rivers and Harbors Act

ROD-Record of Decision

ROV-Remotely Operated Vehicle

RPI-Reef Priority Index

RPS- Renewable Portfolio Standard

SARS-Special Artificial Reef Site

SEA-Strategic Environmental Assessment

TARP-Texas Artificial Reef Program

APPENDIX A.

CHAPTER 1 TABLES AND FIGURES

Table A.1.

Structure[a] Inventory in the Gulf of Mexico (2003)

Water Depth (ft)	WGOM			CGOM			GOM Auxiliary
	CAIS	WP	FP	CAIS	WP	FP	
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

Source: USDOI, MMS, 2008d.

Footnote: (a) Structures are classified as caissons (CAIS), well protectors (WP) and fixed platforms (FP) across the Western and Central Gulf of Mexico (WGOM, CGOM) planning areas. An auxiliary structure is a structure that has never produced hydrocarbons but serves in an auxiliary role, say as a quarters facility, flare tower, or storage platform.

Table A.2.

Deepwater Production Facilities Installed in the Gulf of Mexico, Including Plans Through 2006

Structure Type	Number
Fixed Platform	5
Compliant Tower	3
TLP	8
Small TLP	6
Spar	4
Truss Spar	8
Semi FPS	5
Subsea	164

Source: USDOI, MMS, 2008d.

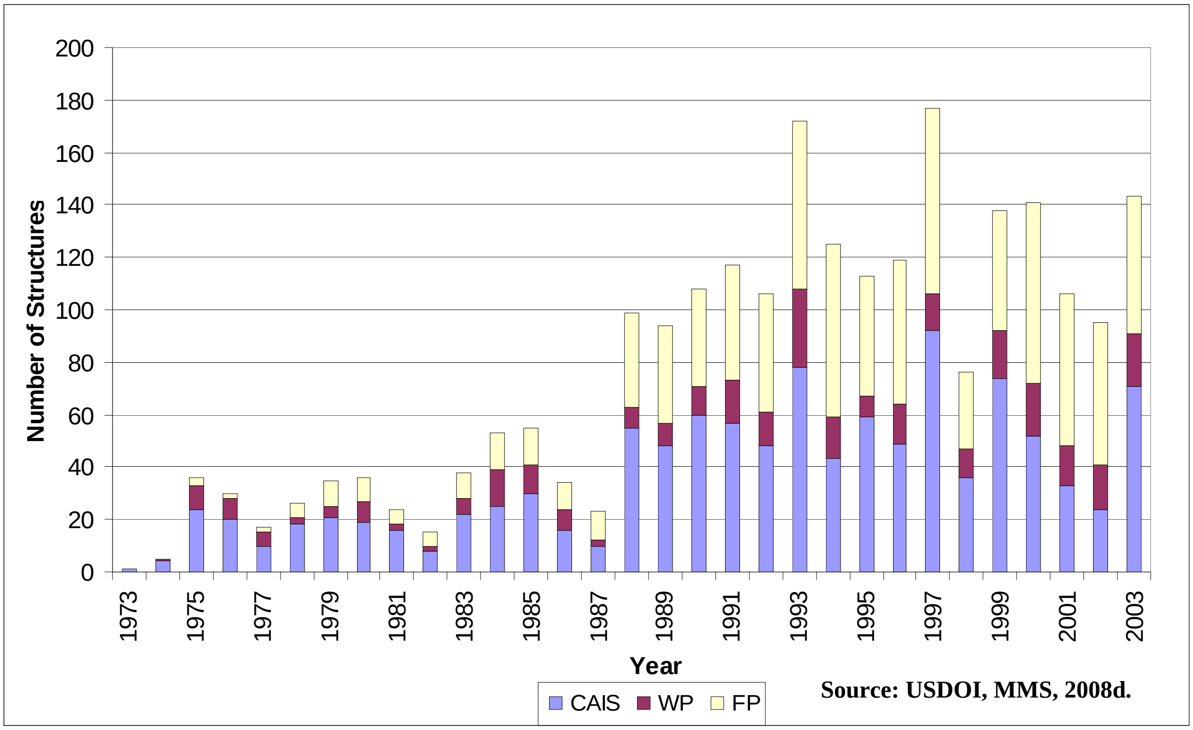


Figure A.1. Structures Removed in the Outer Continental Shelf of the Gulf of Mexico (1973-2003).

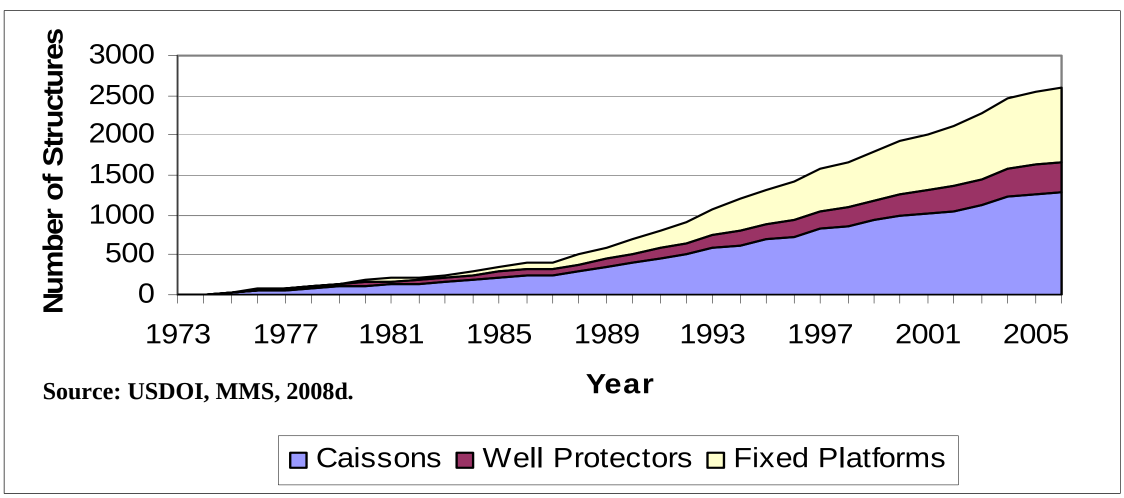


Figure A.2. Cumulative Number of Structures Removed in the GOM (1973-2006).

Source: Twachtman Snyder & Byrd, Inc., 2006.

Figure A.3. Caisson Structures.

Source: Twachtman Snyder & Byrd, Inc., 2006.

Figure A.4. Well Protector and Fixed Platform Structures.

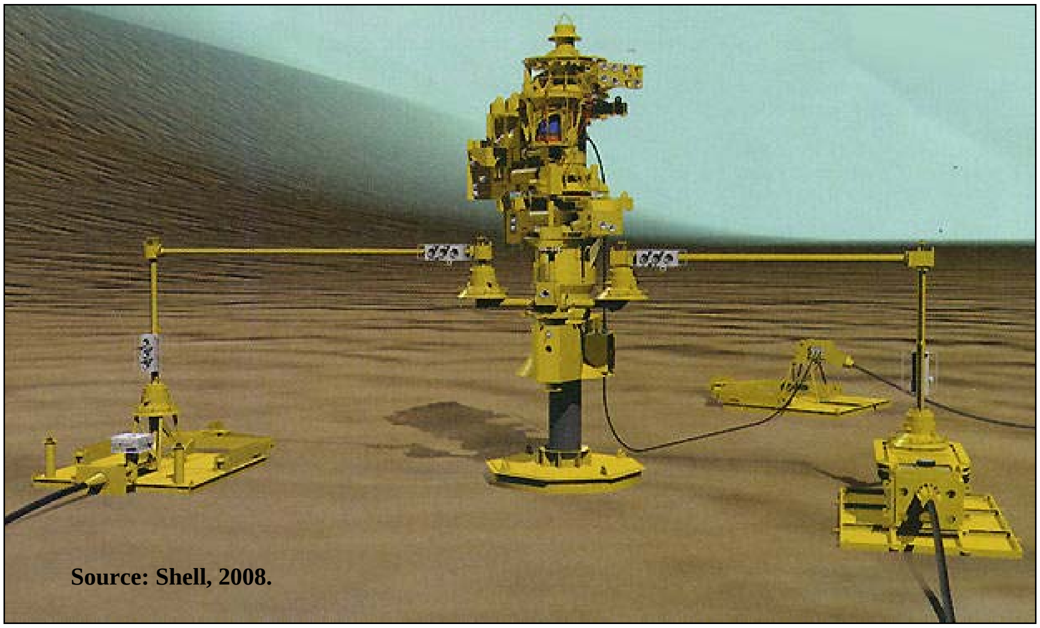
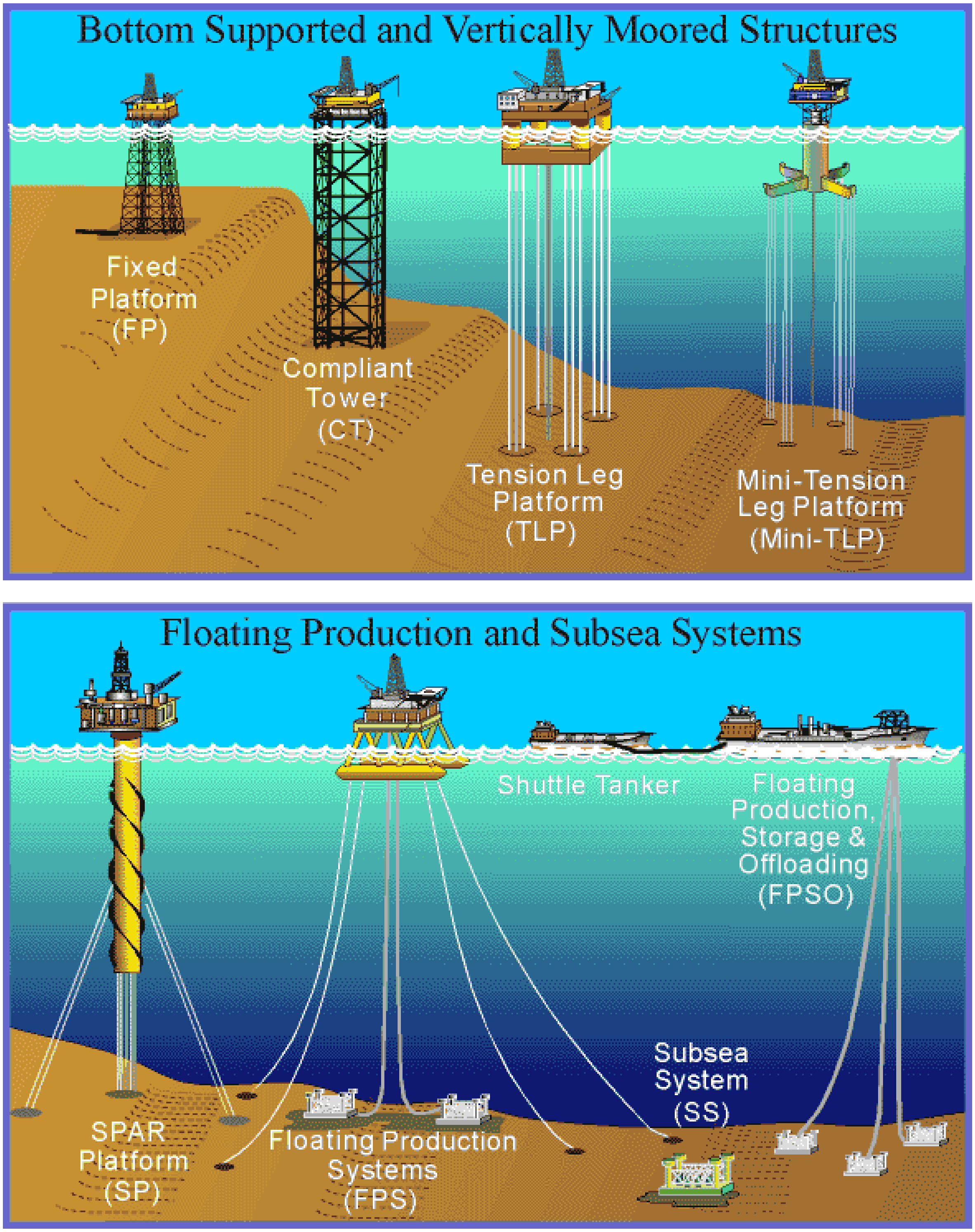
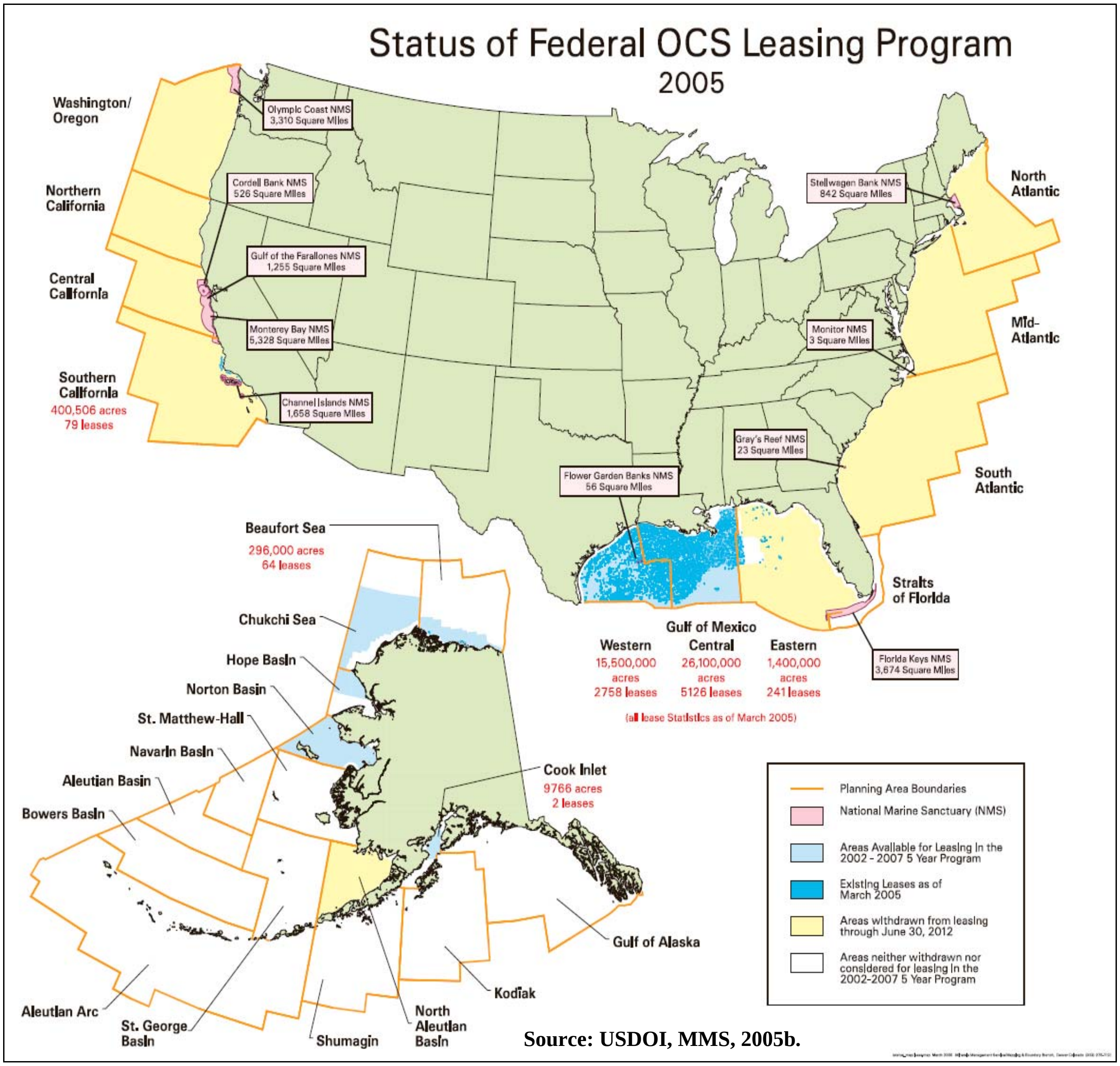


Figure A.5. Subsea Equipment and Configuration.



Source: Baud et al., 2002.

Figure A.6. Deepwater Development Strategies.



Source: USDOI, MMS, 2005b.

Figure A.7. Federal Outer Continental Shelf Leasing Program.

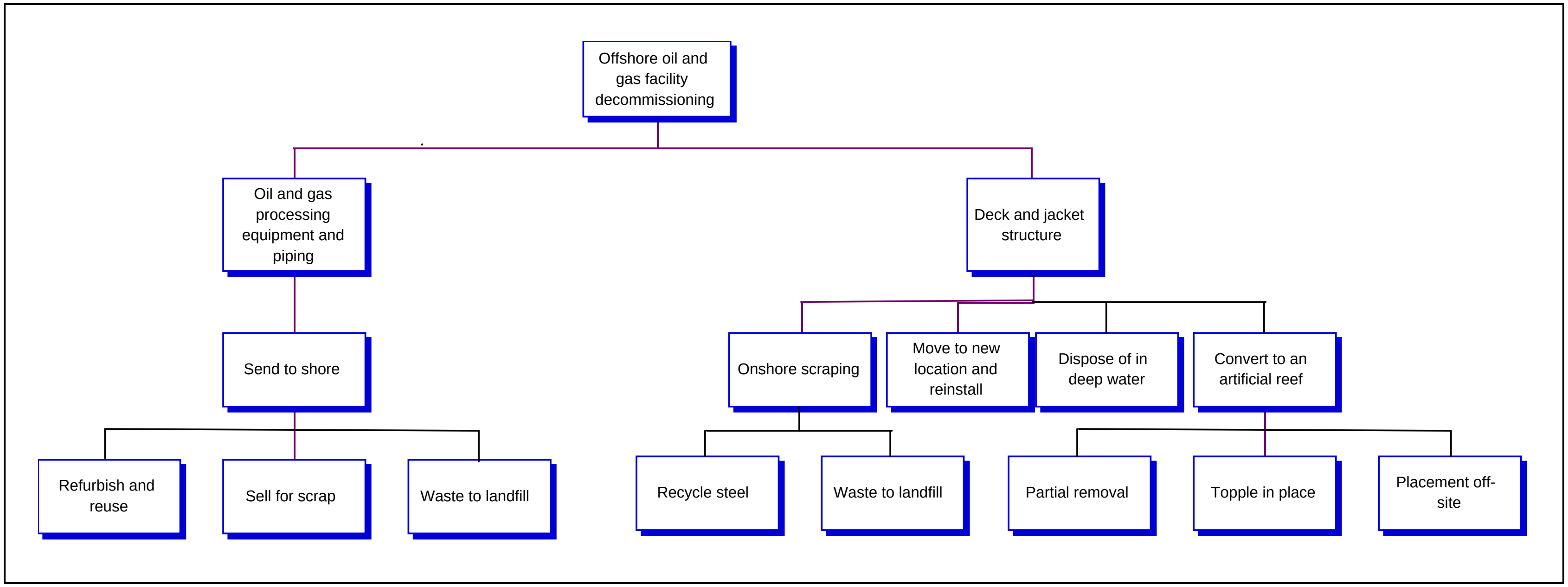


Figure A.8. Offshore Oil and Gas Facility Decommissioning Tree.

Figure A.9. Derrick Barge Arrives On-Site and Removes the Deck Module.

Source: USDOC, NMFS, 2004.

Figure A.10. Explosives Technicians Prepare and Load Charges into Conductors and Legs.

Figure A.11. Aerial View of Job Site during Blast and Detonation.

Source: DEMEX, 2004.

Figure A.12. Severed Piles and Conductors Loaded onto Derrick Barge.

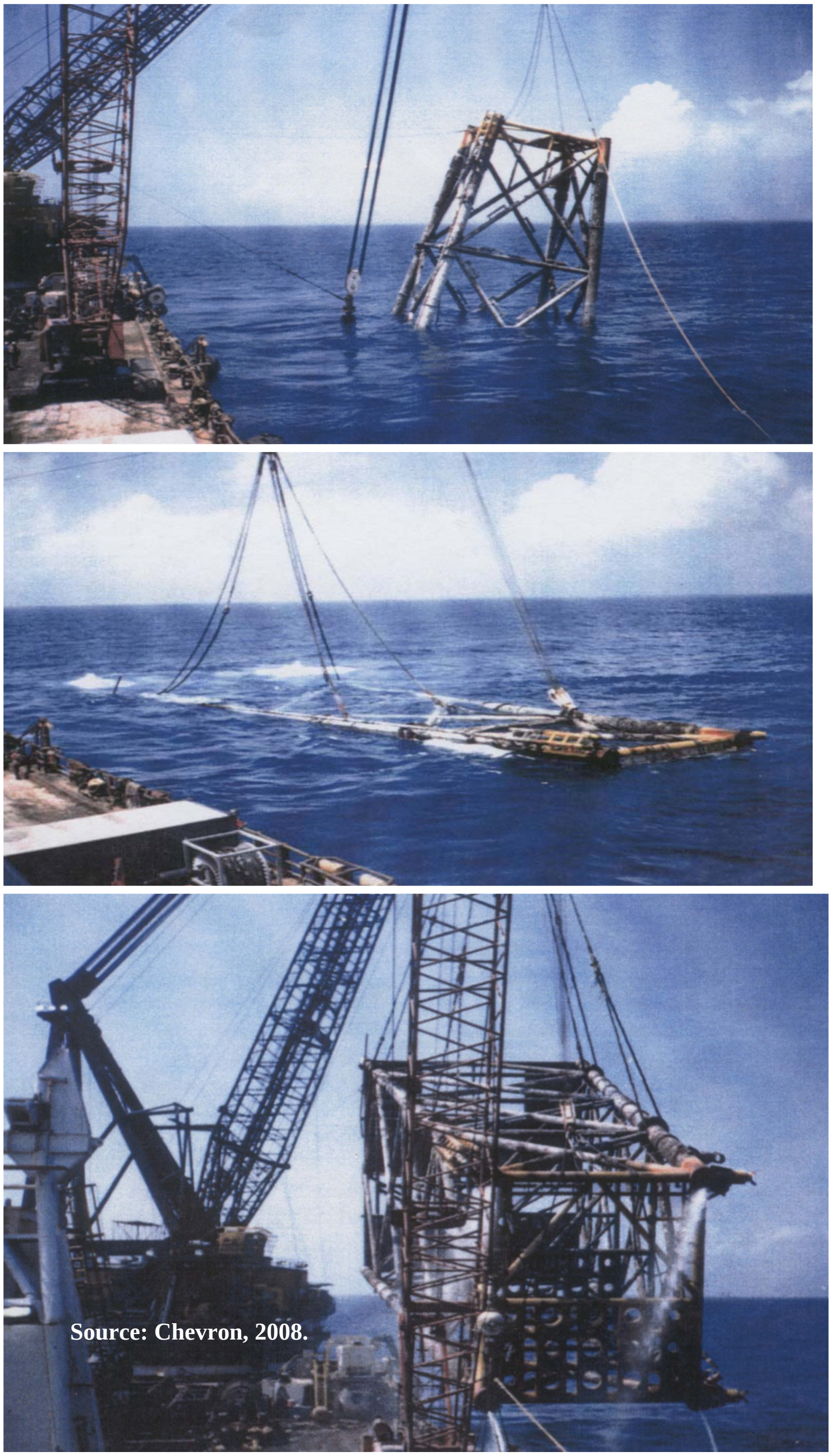
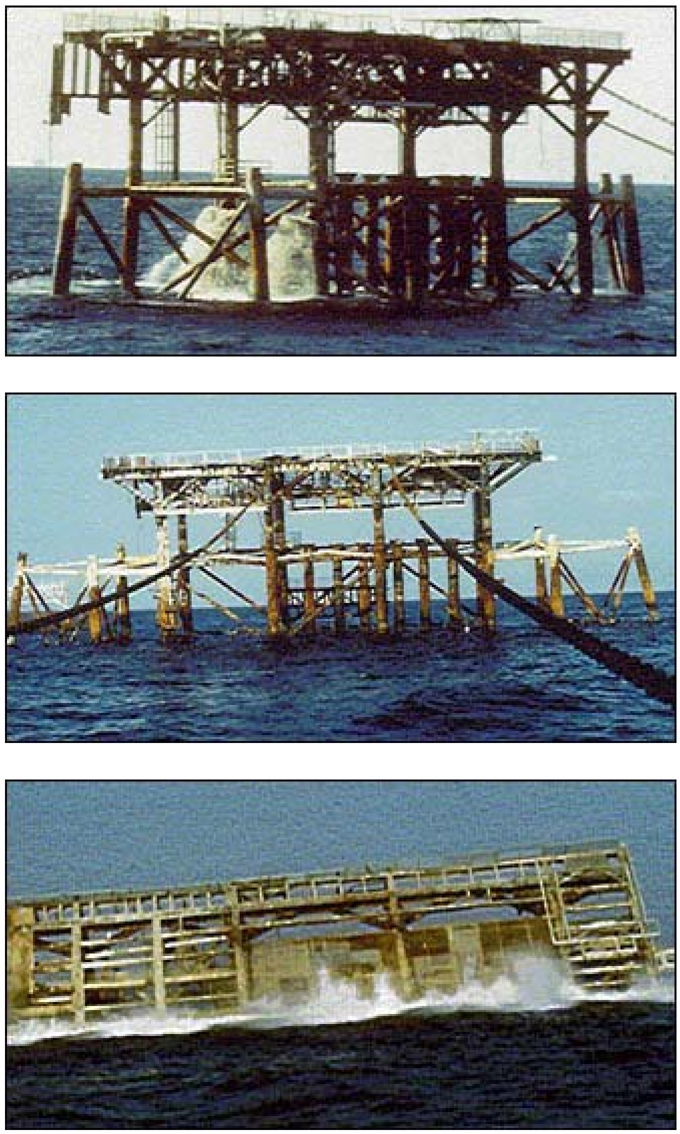

Source: Chevron, 2008.

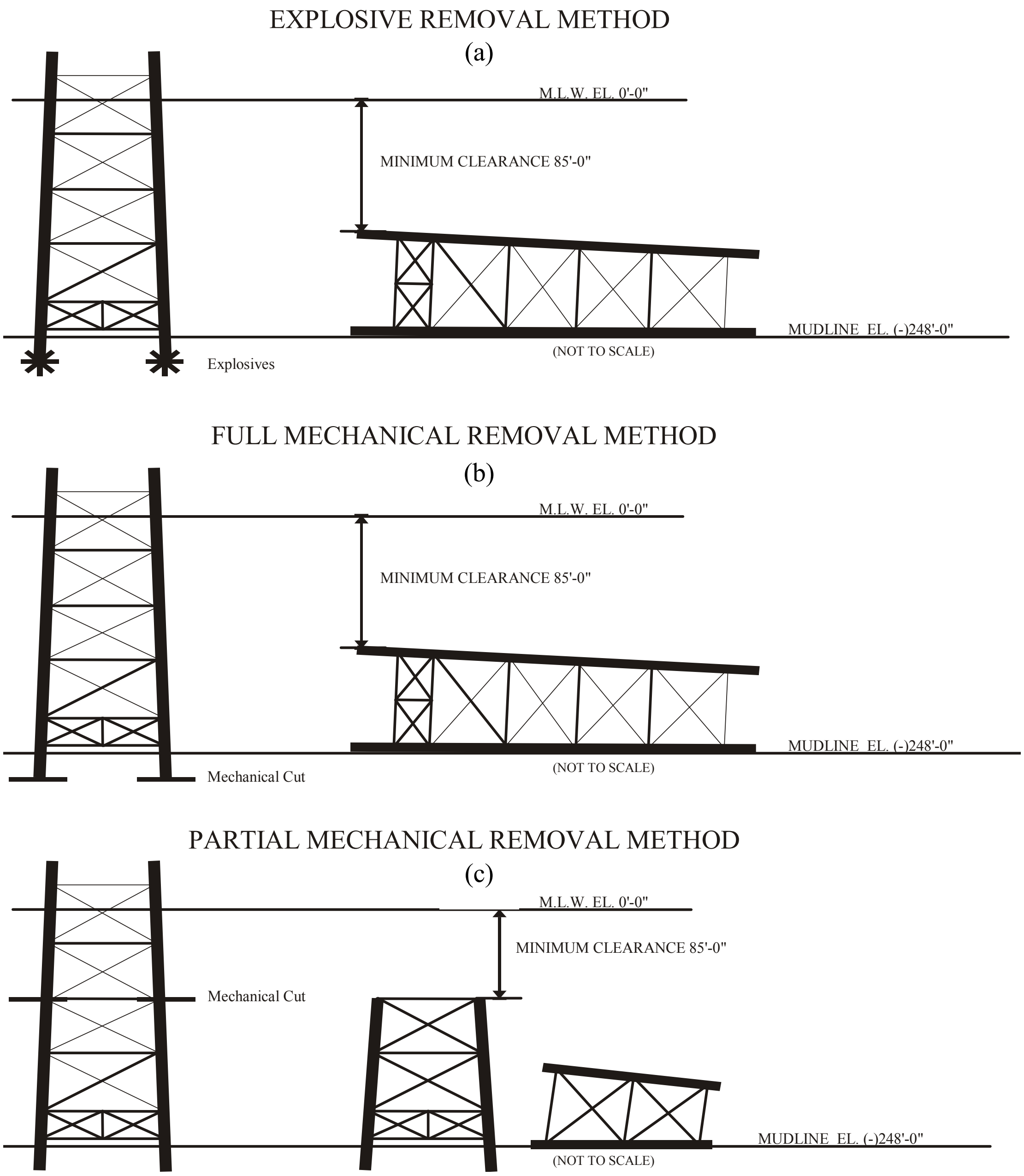
Figure A.13. Jacket Lifted from Water.

Figure A.14. Jacket and Deck Transported to Shore or Artificial Reef Site.



Source: Louisiana Department of Wildlife and Fisheries, 2009.

Figure A.15. Structure Toppled-in-Place.



Source: Texas Parks and Wildlife Department, 2008.

Figure A.16. Platform Removal Methods. (M.L.W.EL.=Mean Low Seawater Elevation).

Source: B&J Martin, Inc., 2006.

Figure A.17. Gorilla Net Application.

APPENDIX B.

CHAPTER 2 TABLES AND FIGURES

Table B.1.

Louisiana Artificial Reef Planning Areas

Number	Planning Area	Blocks
1	West Cameron	586-587, 594-595, 608-609, 616-617
2	East Cameron	254-256, 269-274; Vermillion blocks 262, 281-282
3	Ship Shoal	204-209, 214-219, 228-233
4	South Marsh Island I	65-67, 75-77, 80-82
5	South Marsh Island II	130-133, 136-139, 146-149
6	Eugene Island	346-350, 363-372; Ship Shoal blocks 320, 343-344
7	South Timbalier	128-135, 151-154
8	West Delta	69-76, 89-96
9	Main Pass	144-145, 272-273, 292-306

Source: Louisiana Department of Wildlife and Fisheries, 2009.

Table B.2.

Louisiana Artificial Reef Program Structure Donations (1987-2003)

Year	Structures	Donation ($)
1987	1	250,000
1988	4	350,000
1989	0	0
1990	4	875,000
1991	4	1,292,870
1992	10	1,326,876
1993	13	1,134,750
1994	16	1,266,442
1995	4	564,840
1996	4	736,281
1997	8	1,167,385
1998	4	327,642
1999	10	2,374,657
2000	12	1,757,243
2001	3	145,000
2002	8	1,244,136
2003	12	4,103,981
TOTAL	117	20,817,102[a]

Source: Louisiana Department of Wildlife and Fisheries, 2009.
Footnote:(a) Includes $1.9M for a barge donation.

Table B.3.

Louisiana Artificial Reef Program Statistics (1987-2003)

Structure Type	Variable[a] (Unit)	Towed	Not Towed
3-pile	*DON* ($/structure)	46,667 (3)[b]	450,600 (1)
	DON/NP ($/pile)	15,556 (9)	150,000 (3)
4-pile	*DON* ($/structure)	97,310 (43)	246,484 (16)
	DON/NP ($/pile)	24,327 (129)	61,621(64)
8-pile	*DON* ($/structure)	150,117 (34)	212,009 (20)
	DON/NP ($/pile)	18,348 (260)	24,369 (174)

Source: Louisiana Department of Wildlife and Fisheries, 2009.

Footnote: (a) The donation (*DON*) and donation per pile (*DON/NP*) are aggregated according to structure type (3-pile, 4-pile, 8-pile) and disposition (towed, not towed).

(b) Numbers in parenthesis represent the number of elements in the set.

Table B.4.

Operator Donation (1987-2003)

Operator	Structures	Donation ($)	Percentage of Total Donation
ChevronTexaco	34	3,349,064	17.7
Kerr McGee	10	711,508	3.8
CNG	6	1,188,350	6.3
ExxonMobil	6	1,200,000	6.3
Apache	6	701,793	3.7
Forest Oil	6	3,128,500	16.5
Hunt	6	926,404	4.9
BP/Amoco	4	758,546	4.0
Pioneer	4	365,463	1.9
Conoco	3	301,130	1.6
Coastal	3	560,000	3.0
Unocal	2	592,870	3.1
Newfield	2	506,008	2.7
Oryx	2	317,340	1.7
Delmar	2	99,729	0.5
Subtotal	96	14,706,705	77.7
Other (21)	21	4,205,397	22.2
TOTAL	117	18,912,102	100.0

Source: Louisiana Department of Wildlife and Fisheries, 2009.

Table B.5.

Structures Removed and Reefed in the Central Gulf of Mexico (1987-2002)

Water Depth (ft)	Structures Removed WP	Structures Removed FP	Structures Reefed WP+FP	P(Reef)[a] (%)	P(Not Towed) (%)
0-20	12	40	0	0	0
21-100	112	352	2	0.4	0
101-200	41	151	60	31.3	25.0
201-400	4	70	43	58.1	35.2
400+	0	1	0	0	0
TOTAL	169	614	105	13.4	31.6

Footnote: (a) The capture probability is computed as the ratio of all structures reefed in the Central GOM from 1987-2002 to the total number of well protectors (WP) and fixed platform (FP) removed.

Table B.6.

LARP Donation Model Results – I

Parameter	DON = $\alpha_0 + \alpha_1$ WD + α_2 DIST + α_3 NP+ α_4 TIP		
	Not Towed[a]	Towed	All
α_0	-6,746 (*)	-102,238 (-3.1)	22,568 (*)
α_1	1,565 (1.7)	740 (6.4)	1,020 (3.3)
α_2	-5,645 (-1.2)	-282 (-1.1)	-200 (*)
α_3		11,831 (3.4)	4,778 (*)
α_4			145,429 (2.9)
n	37	80	117
R^2	0.28	0.64	0.37

Footnote: (a) Structures not towed include toppling-in-place and partial removals.
(*) denotes t-statistics < 1.

Table B.7.

LARP Donation Model Results – II

Parameter	$DON = \alpha_0 + \alpha_1\,WD + \alpha_2\,DIST$				
	Not Towed			Towed	
	3,4-pile[a]	3,4-pile	8-pile	3,4-pile	8-pile
α_0	-793 (-1.1)	-428,365 (-1.1)	53,433 (*)	-95,486 (-3.7)	37,069 (1.1)
α_1	654 (2.0)	4,409 (1.7)	816 (2.5)	902 (8.6)	222 (2.5)
α_2				-26 (*)	-323 (*)
n	16	17	20	46	34
R^2	0.47	0.41	0.51	0.79	0.43

Footnote: (a) Excludes an "outlier" $2.5M donation from the data set
(*) denotes t-statistics < 1.

Table B.8.

LARP Donation Model Results – III

Parameter	$DON/NP = \alpha_0 + \alpha_1\,WD + \alpha_2\,DIST + \alpha_3\,TIP$		
	Not Towed	Towed	All
α_0	4,835 (*)	-10,485 (-2.0)	9,721 (-1.8)
α_1	134 (2.4)	156 (7.0)	197 (6.3)
α_2		-47 (-1.0)	-43.5 (-1.5)
α_3			29,119 (2.4)
n	37	80	117
R^2	0.38	0.65	0.48

Footnote: (*) denotes t-statistics < 1

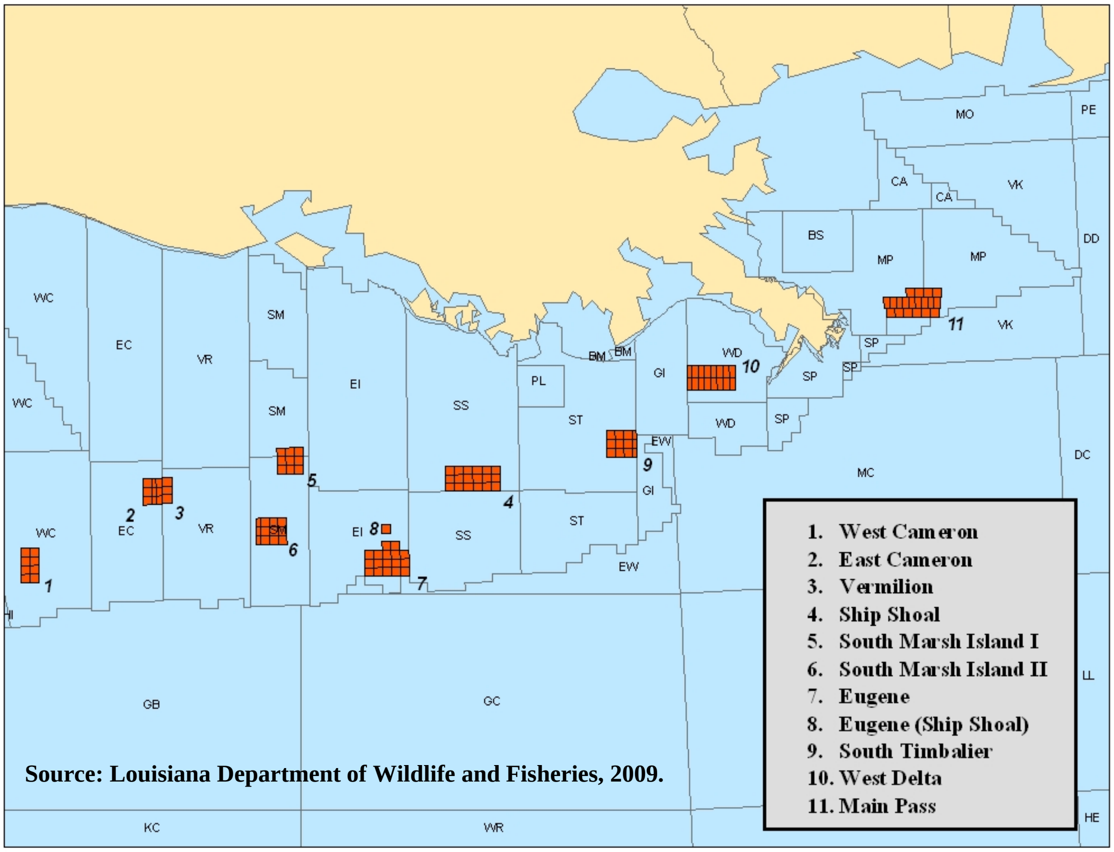


Figure B.1. Louisiana Artificial Reef Program Designated Planning Areas.

APPENDIX C.

CHAPTER 3 TABLES AND FIGURES

Table C.1.

Texas Artificial Reef Program Platform Donations (1990-2003)

Fiscal Year	Donations	Structures	Donation Amount[a] ($)
1990	1	1	35,000
1991	5	5[b]	700,590
1992	6	7	1,104,330
1993	3	4	521,352
1994	4	13	122,333
1995	2	3	612,950
1996	1	1	256,400
1997	3	3	392,239
1998	3	3	482,945
1999	2	3[c]	395,000
2000	3	3	645,000
2001	5	6	1,055,919
2002	12	12	2,088,468
2003	7	9	1,231,959
TOTAL	57	73	9,644,485

Source: Texas Parks and Wildlife Department, 2008.
Footnote: (a) Does not include buoy fee.
(b) Does not include one donated deck.
(c) Does not include one donated caisson.

Table C.2.

Texas Artificial Reef Program Statistics (1990-2003)

Structure Type	Variable[a] (Unit)	Removal Method			
		TIP	TOW	PR	All
3-pile	*DON/NS* ($/structure)	-	64,558	175,600	89,234
			(7)	(2)	(9)
	DON ($/donation)	-	75,318	175,600	100,388
			(6)	(2)	(8)
	DON/NP ($/pile)	-	21,519	58,533	29,745
			(21)	(6)	(27)
	Severance Method[b]	-	5E/2M	0E/2M	5E/4M
			(7)	(2)	(9)
4-pile	*DON/NS* ($/structure)	143,107	17,382[c]	174,178	85,006
		(11)	(20)	(8)	(39)
	DON ($/donation)	174,909	34,765[c]	199,060	127,510
		(9)	(10)	(7)	(26)
	DON/NP ($/pile)	35,776	4,346[c]	42,225	21,116
		(44)	(80)	(33)	(157)
	Severance Method	9E/2M	16E/4M	0E/8M	25E/14M
		(11)	(20)	(8)	(39)
8-pile	*DON* ($/structure)	227,420	143,181	244,875	221,045
		(5)	(5)	(15)	(25)
	DON ($/donation)	227,420	143,181	282,548	240,266
		(5)	(5)	(13)	(23)
	DON/NP ($/pile)	28,428	18,840	31,128	28,195
		(40)	(38)	(118)	(196)
	Severance Method	5E/0M	5E/0M	0E/15M	10E/15M
		(5)	(5)	(15)	(25)

Source: Texas Parks and Wildlife Department, 2008.

Footnote: (a) Donation amount is presented on a structure (*DON/NS*), donation (*DON*), and pile (*DON/NP*) basis. The number of elements in each category is presented in parenthesis. Note that a donation may include more than one structure and so the number of donations will be less than the number of structures in each category.

(b) "E" denotes explosive removal and "M" denotes mechanical removal. The number of explosive and severance removals are shown for each category.

(c) 14 of the 20 structures provided zero donation, and so the unit cost savings may not be representative of the towing operation.

Table C.3.

Top 5 Operator Donations to TARP

Operator	Structures	Total Donation ($)	Program Percent[a](%)
El Paso	9	1,866,517	19
CNG	3	645,000	7
ChevronTexaco	5	572,150	6
Samedan	4	401,078	4
Cal Dive/Blue Dolphin Energy	10	350,000	4

Source: Texas Parks and Wildlife Department, 2008.

Footnote: (a) Percentage of total program donation.

Table C.4.

Removed and Reefed Structures in the Western Gulf of Mexico (1990-2002)

Water Depth (ft)	Structure Type			Structures Reefed	*P*(Reef) [a] (%)
	CAIS	WP	FP		
0-20	0	0	1	0	0
21-100	60	36	50	9	11
101-200	7	5	58	41	65
201-400	0	5	23	23	82
400+	0	0	0	0	-
TOTAL	67	46	132	73	42

Source: Texas Parks and Wildlife Department, 2008.

Footnote: (a) P(Reef) is computed as the number of structures reefed during 1990-2002 divided by the total number of well protectors (WP) and fixed platforms (FP) removed during this time.

Table C.5.

TARP Donation Model Results – I

Parameter	$DON = \alpha_0 + \alpha_1 WD + \alpha_2 DIST + \alpha_3 NP + \alpha_4 NS$		
	TOW	*TIP*	*PR*
α_0	-156,543 (-2.8)	-115,634 (-1.1)	-56,418 (*)
α_1	893 (3.9)	1,166 (1.9)	1,089 (2.6)
α_2	-193 (*)		
α_3	14,852 (2.8)	12,074 (1.1)	11,831 (1.5)
α_4	2,157 (*)		6,930 (*)
n	21	14	22
R^2	0.86	0.69	0.67

Footnote: t-statistics presented in (); * denotes t-statistic < 1.

Table C.6.

TARP Donation Model Results – II

Parameter	$DON/NP = \alpha_0 + \alpha_1 WD + \alpha_2 DIST + \alpha_3 NS$		
	TOW	*TIP*	*PR*
α_0	-23,090 (-1.8)	22,296 (1.4)	17,232 (*)
α_1	218 (4.1)	141 (1.5)	152 (1.8)
α_2	-83 (*)		
α_3	275 (*)	-2,937 (-1.7)	-5,860 (*)
n	21	14	22
R^2	0.79	0.48	0.59

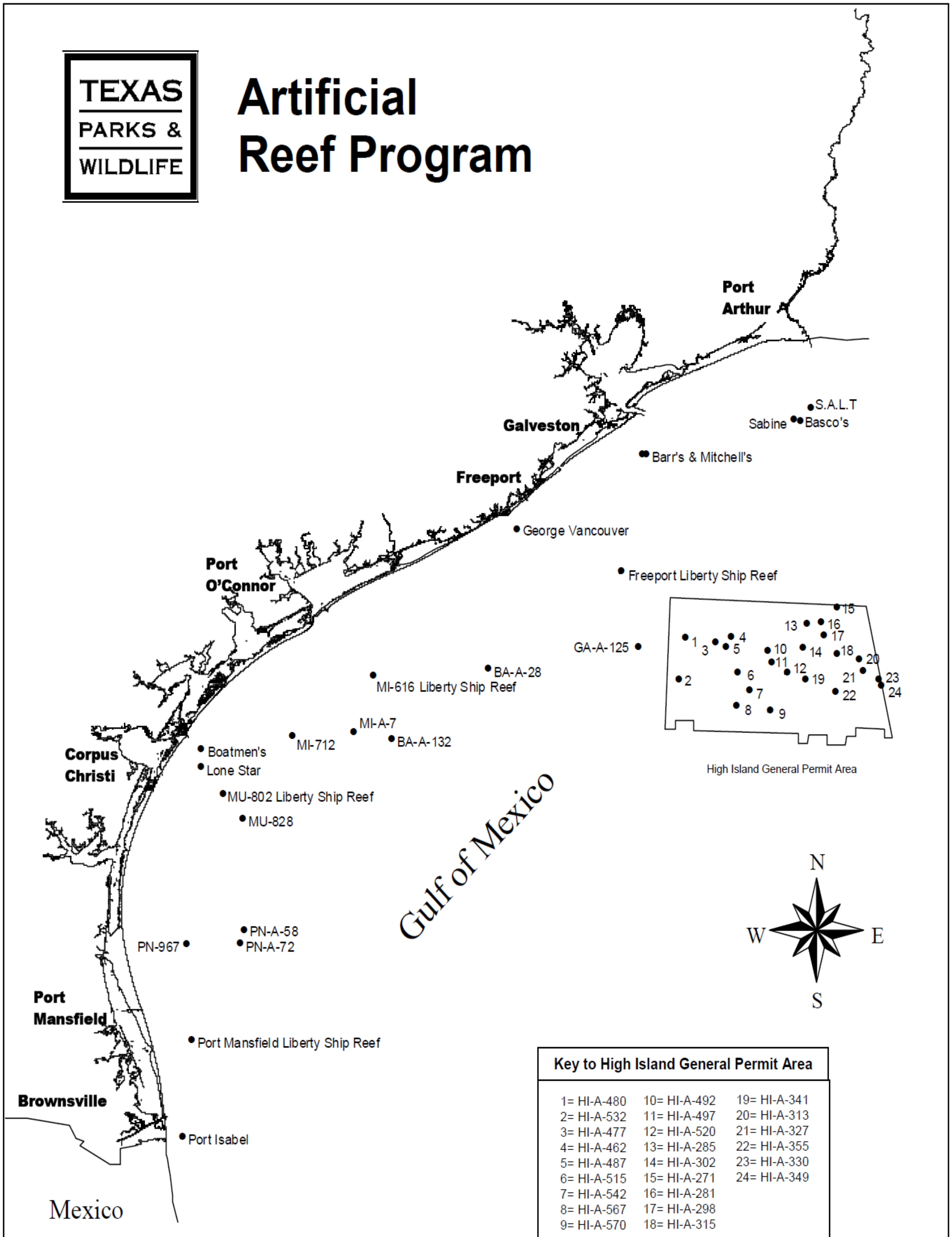
Footnote: t-statistics presented in (); * denotes t-statistic < 1.

Table C.7.

TARP Donation Model Results – III

Parameter	DON = $\alpha_0 + \alpha_1$ WD + α_2 DIST + α_3 NP+ α_4 NS+ α_5 ST+ α_6 TIP+ α_7 MECH	
	DON	*DON/NP*
α_0	-150,663 (-2.7)	-15,997 (-1.6)
α_1	1,014 (5.0)	208 (6.0)
α_2	-24 (*)	-102 (*)
α_3	3,169 (2.3)	
α_4	4,020 (*)	-1,571 (*)
α_5	43,354 (*)	-12,894 (-3.7)
α_6	102,141 (3.4)	13,616 (2.6)
α_7	40,340 (1.8)	10,557 (2.6)
n	57	57
R^2	0.84	0.82

Footnote: t-statistics presented in (); * denotes t-statistic < 1.



Source: Texas Parks and Wildlife Department, 2008.

Figure C.1. Texas Artificial Reef Sites and High Island General Planning Area.

APPENDIX D.

CHAPTER 4 TABLES AND FIGURES

Table D.1.
Structure and Rig Damage Caused by Hurricanes Ivan, Katrina, and Rita

	Ivan	Katrina	Rita
Platforms destroyed	7	44	69
Platforms extensively damaged	20	20	32
Rigs adrift	5	6	13
Rigs destroyed	1	4	4
Rigs extensively damaged	4	9	10

Source: Kaiser and Kasprzak, 2008.

Table D.2.

Louisiana Artificial Reef Program Structure Donations (1987-2006)

Year	No. Structures	Total Donation ($)	Average Donation ($/structure)
1987	1	250,000	250,000
1988	4	350,000	87,500
1990	4	875,000	218,750
1991	4	1,292,870	323,218
1992	10	1,326,876	132,688
1993	13	1,132,404	87,108
1994	17	1,266,442	74,497
1995	5	564,840	112,968
1996	4	736,280	184,070
1997	8	1,167,385	145,923
1998	4	327,641	81,911
1999	11	4,274,657	386,605
2000	12	1,757,244	146,437
2001	3	145,000	48,333
2002	9	1,244,136	138,237
2003	12	4,103,981	341,998
2004	14	3,384,689	241,764
2005	6	2,223,326	370,554
2006	6	2,820,102	470,017
Total	147	29,242,874	198,931

Source: Louisiana Department of Wildlife and Fisheries, 2009.

Table D.3.

Special Artificial Reef Site Projects and Platform Additions

Area/Block	Source	Donor	Date	WDSS[a]	WDRS[a]	Event/Rational
ST-86	ST-86[b]	ODECO	9/20/91	91	91	Hurricane Juan
WD-134	WD-134A	BOEMRE	9/12/65	280	280	Hurricane Betsy
WD-134	WD-134B	Kirby	1/21/92	280	280	Addition
WD-134	WD-138	Shell	6/4/92	275	275	Addition
WD-134	WD-133	Elf	4/17/93	280	280	Addition
WD-134	SP-54	Vastar	6/2/99	297	282	Addition
WD-134	SP-78	Texaco	4/25/02	280	274	Addition
WD-134	WD-122C	Maritech	8/12/04	227	280	Addition
GI-9	GI-9	Freeport	1/14/99	52	52	Construction accident
GI-9	AOD[c]	AOD	1/31/99	51	51	Sunk during construction
MP-243	MP-243A	Coastal	6/22/00	196	196	Hurricane Georges
MP-243	MP-243B	Coastal	6/22/00	196	196	Addition
MP-243	MP-243A	Coastal	6/22/00	196	196	Addition
MP-243	MP-198A	El-Paso	10/10/00	196	196	Addition
EI-313	Penrod60[c]	None	6/19/72	0	236	
EI-313	EI-313A	Texaco	8/3/00	236	236	Biological Study
EI-313	EI-313A	Texaco	8/3/00	236	236	Biological Study
EI-313	EI-295	POGO	9/30/02	211	236	Addition
EI-313	EI-335	Murphy	9/8/04	272	236	Addition
EI-313	EI-231CB	Chevron	9/9/04	219	236	Addition
EI-313	EI-315B	Newfield	12/20/05	250	250	Addition
EI-309	EI-309	Forest	9/18/03	225	225	Biological Study/ Hurricane Lili
EI-324	EI-324	Newfield	9/23/03	265	256	Biological Study/ Hurricane Lili
EI-273	EI-273	Forest	4/24/04	191	191	Biological Study/ Hurricane Lili
EI-322	EI-322AP	BP	6/22/04	255	255	Biological Study/ Hurricane Lili
EI-322	EI-322AD	BP	6/22/04	255	255	Biological Study/ Hurricane Lili
SP-89	SP-89	Marathon	7/01/04	393	393	Deepwater Reef Criteria
EI-384	EI-384	W&T	4/28/05	431	431	Deepwater Reef Criteria
VE-395	VE-395	W&T	7/28/05	428	428	Deepwater Reef Criteria

Source: Louisiana Department of Wildlife and Fisheries, 2009.
Footnote: a) WDSS = water depth source site; WDRS = water depth reef site.
b) Drilling rig.
c) Derrick barge.

Table D.4.

Special Artificial Reef Sites Approved in 2006

Area/Block	Water Depth (ft)	Donor	Approval	No. Platforms	RPI
WD-117C	214	AngloSwiss	June 2006	5	40
SS-269A	206	Maritech	June 2006	3	18
WD-103/104	223	Apache	June 2006	3	24
EC-222	124	ERT	June 2006	2	16
VE-255	158	Stone	June 2006	2	16
EI-276	176	Chevron	June 2006	3	18
VE-245	128	Chevron	June 2006	3	24
GI-40/48	90	BP	Nov 2006	8	64
ST-161	117	Apache	Nov 2006	3	24
SMI-108	183	Stone	Nov 2006	3	18

Source: Louisiana Department of Wildlife and Fisheries, 2009.

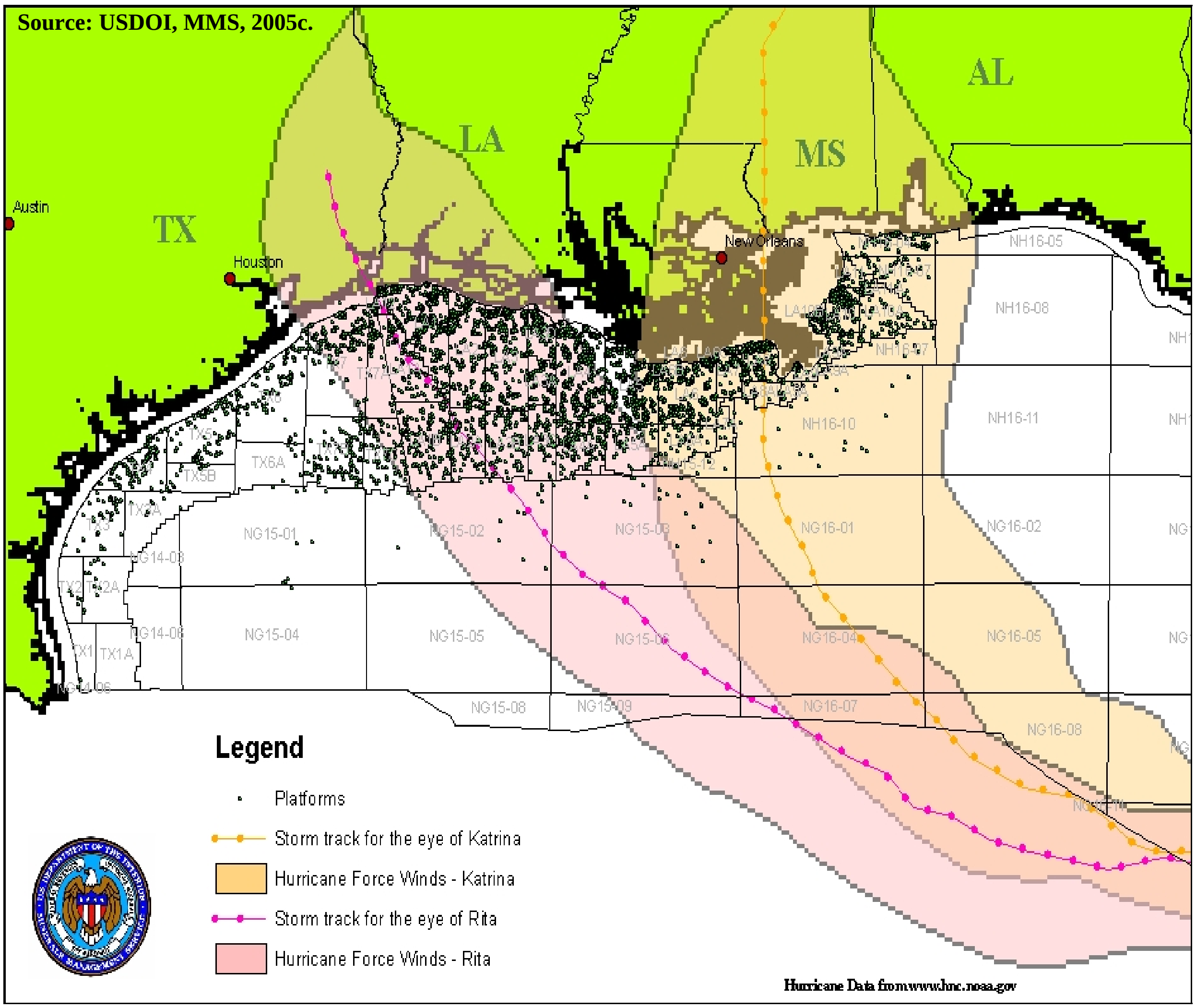


Figure D.1. Hurricane Katrina and Rita Tracks Relative to Offshore Oil and Gas Infrastructure.

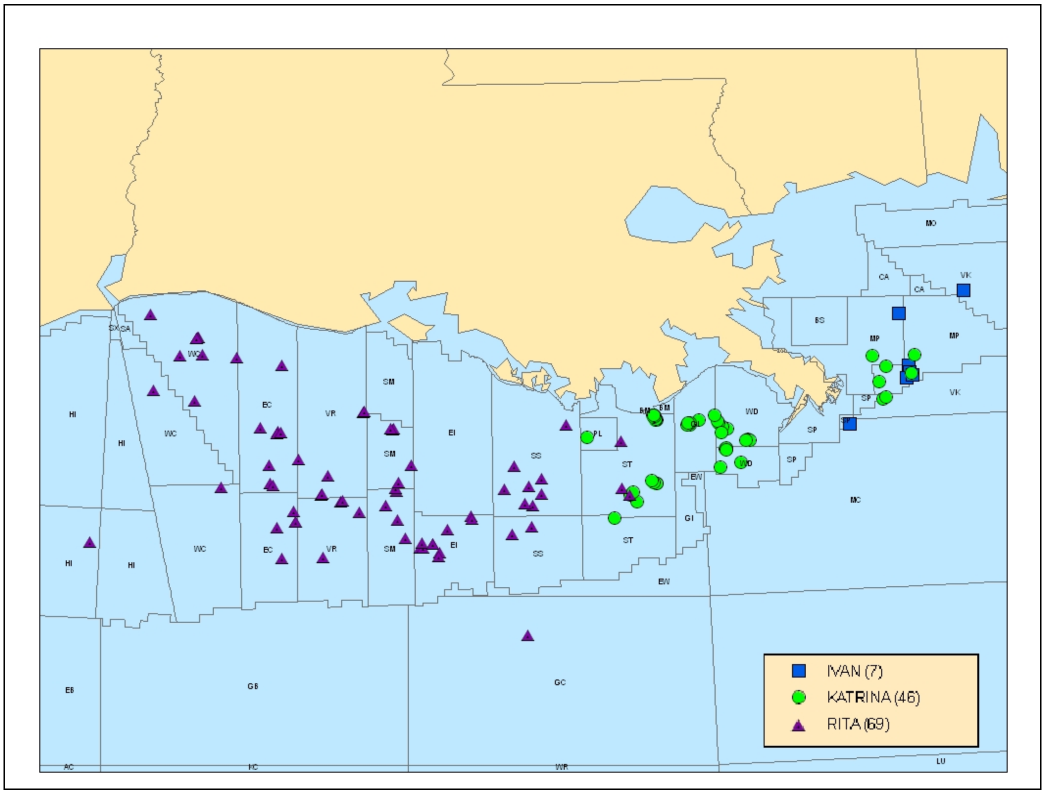


Figure D.2. Structures Destroyed in Hurricanes Ivan, Katrina, and Rita.

Source: Kaiser and Kasprzak, 2008.

Figure D.3. Before and After - Devon Energy's SA-1 Platform Destroyed at South Marsh 128.

Source: Kaiser and Kasprzak, 2008.

Figure D.4. Before and After - BT Operating Company Platform Destroyed at Eugene Island 294A.

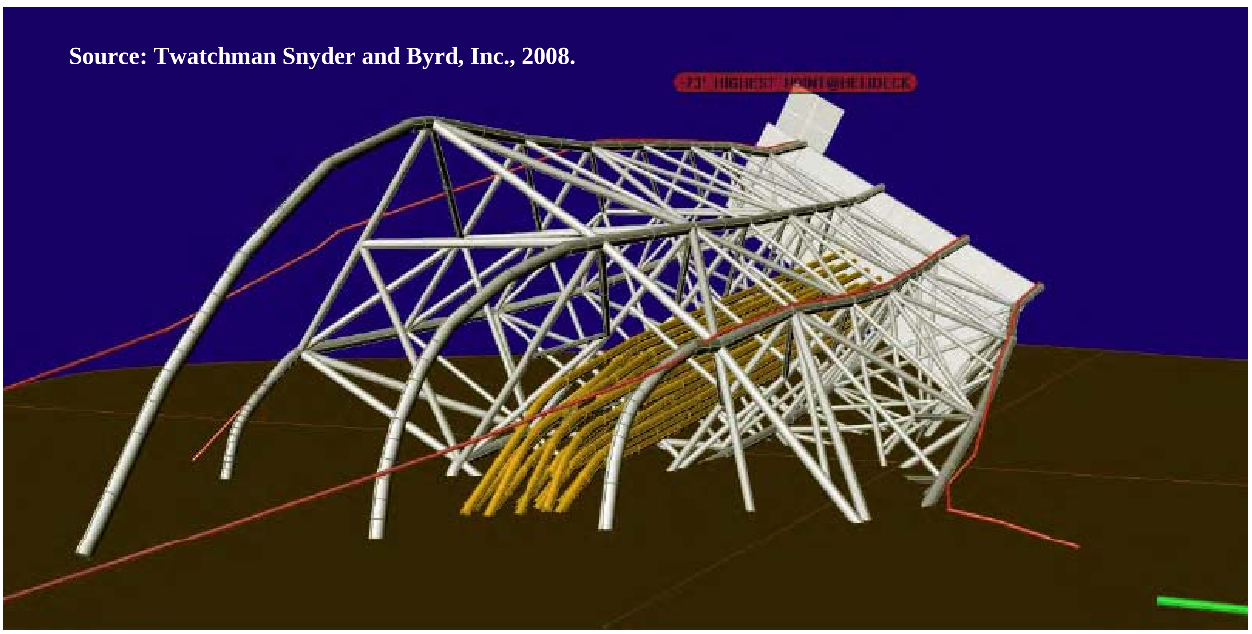


Figure D.5. Model Rendition of Hurricane Destroyed Structure Lying Horizontally on the Seafloor. Note the Bent Conductors Entering the Seabed.

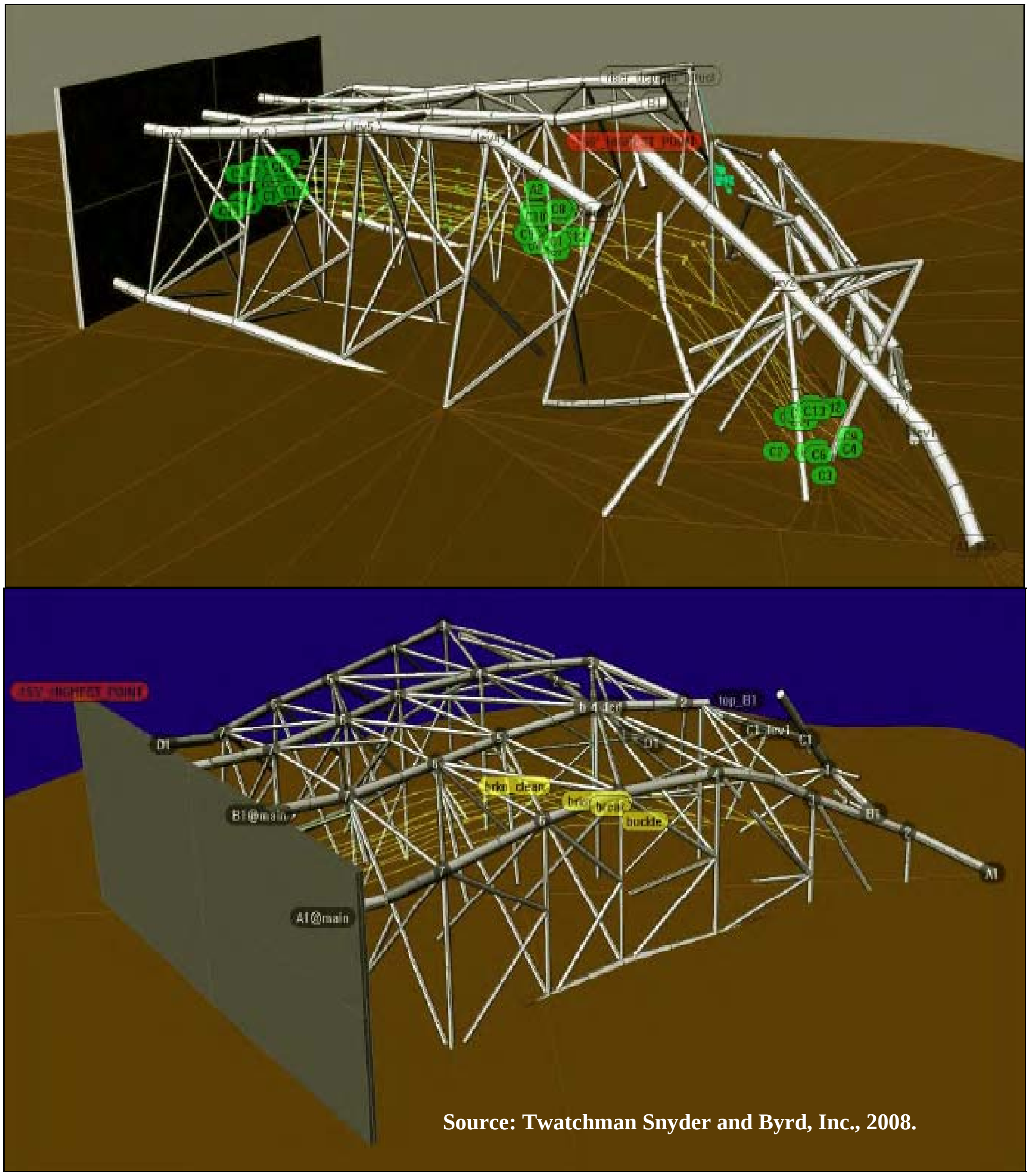


Figure D.6. Model Rendition of Hurricane Destroyed Structure Lying Horizontally on the Seafloor.

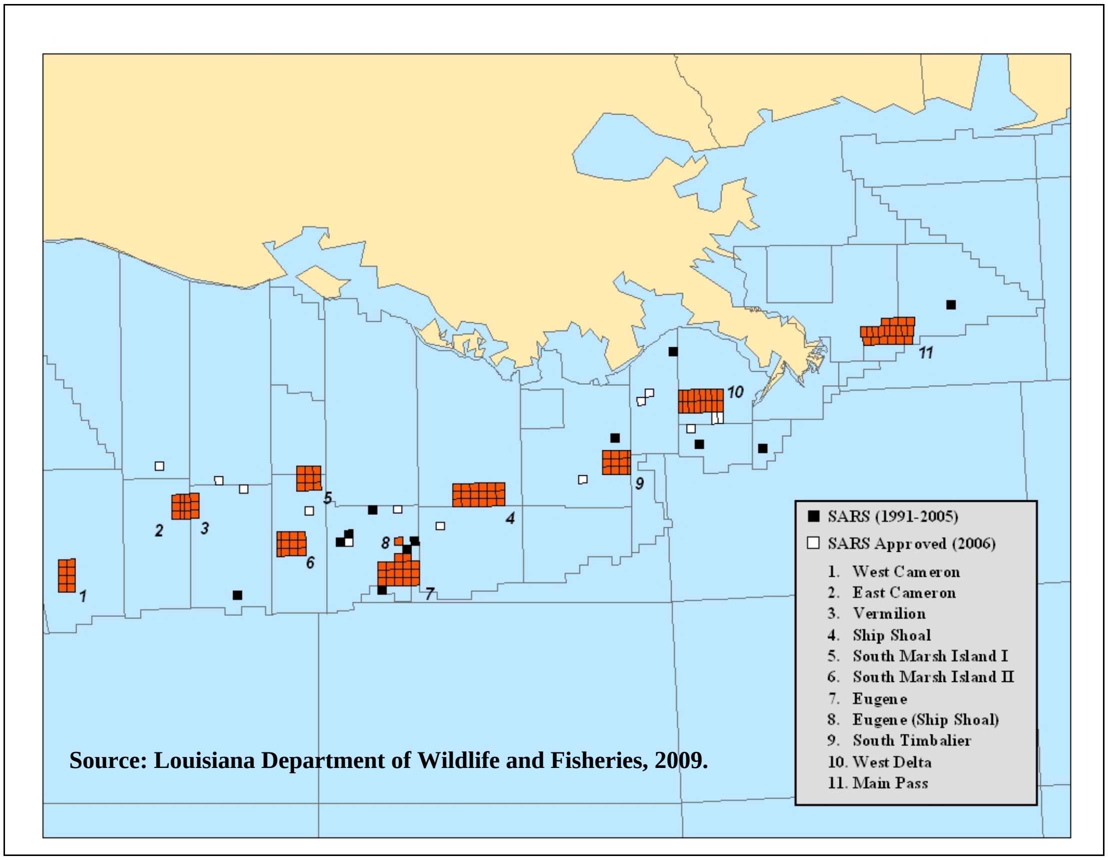


Figure D.7. Louisiana Special Artificial Reef Sites 1991-2005 and Approved in 2006.

APPENDIX E.

CHAPTER 5 TABLES AND FIGURES

Table E.1.

Advantages and Disadvantages of Different Logistical Options for Open Ocean Mariculture

Option	Advantages	Disadvantages
Land-Based Crews	▪ Lowest capital costs ▪ Maybe best choice for near shore (under 10 km) sites	▪ No 24-hour on-site security ▪ Long response times for emergencies ▪ High fuel costs for long distance sites ▪ Limited access in poor weather ▪ Limited economies of scale
Feed Buoys/Barges	▪ Relatively low capital costs ▪ Reduced trip frequency and fuel costs	▪ No 24-hour on-site security ▪ Long response times for emergencies ▪ May require larger service vessels
Lift-Boat	▪ 24-hour on site security ▪ Access in most weather conditions ▪ Minimum hurricane risk ▪ Low decommissioning liability	▪ High capital costs ▪ High Operating Costs
Platform-Based Crews	▪ Best option for economies of scale ▪ Access in almost all weather conditions	▪ High capital costs ▪ High decommissioning liability

Table E.2.

Summary of Platform-Based Mariculture Projects in the United States

Project	Location	Time	Technology	Species	Status
Texas Sea Grant Project	Texas	1990s	Net-Pen	Redfish	Ceased
SeaFish Mariculture LLC	Texas	1998-1999	Cages	Red Drum	Ceased
Grace Platform Project	California	2003-2005	Cages	California Yellowtail, California Halibut	Abandoned
GMIT Project	Texas	1998-	Cages	Cobia, Redfish Amberjack, Red Porgy	Financing
OAC Project	Mississippi	2000-2002	Cages	Red Drum	Abandoned

Table E.3.

Projected Sales and Revenues for GMIT Project (million $)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Sales	5.9	18.5	44.6	83.3	101.1	127.2	144.2
Net Income	-1.5	7.2	19.7	30.1	36.2	46.1	52.1
Capital Expenditure	20.2	1.5	2.0	1.0	1.0	1.0	1.0

Source: BioMarine Technologies Company, 2000.

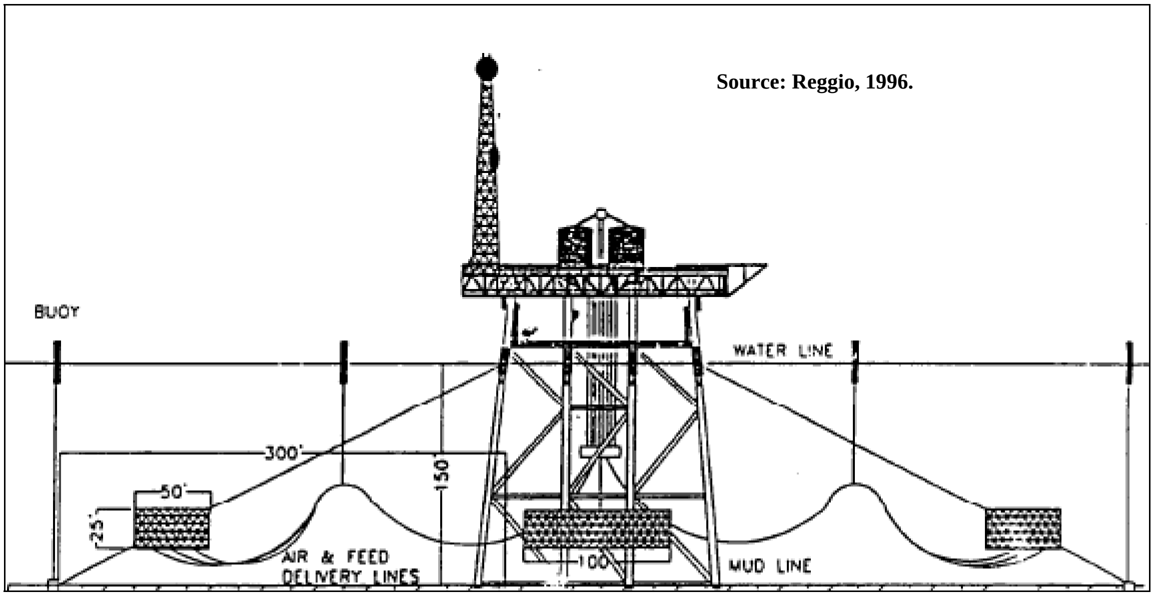
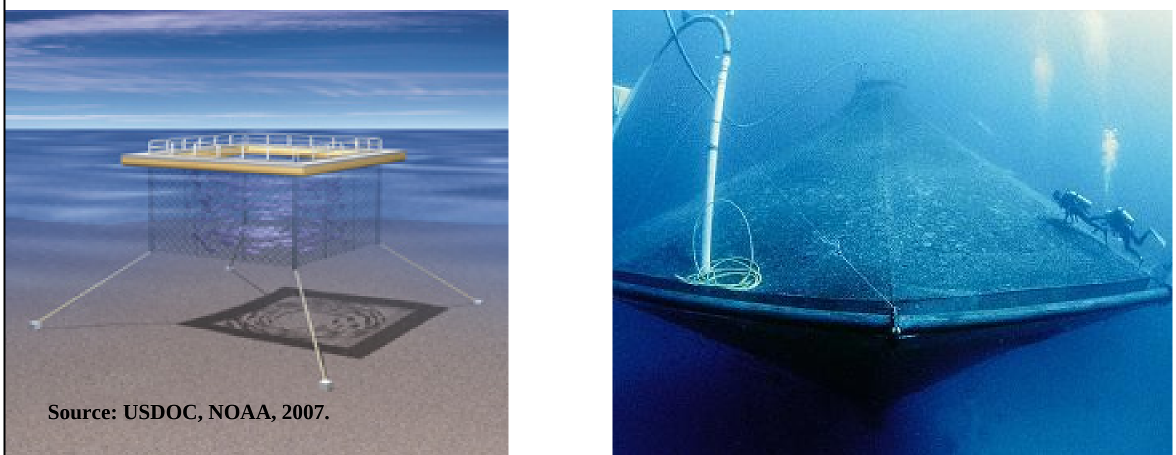


Figure E.1. Artist Conception of Platform-Based Mariculture Operation.



Note: The cage on the left is an anchor tensioned cage while the picture on the right is an example of a semi rigid cage.

Figure E.2. Net-Pen and Submerge Cage.

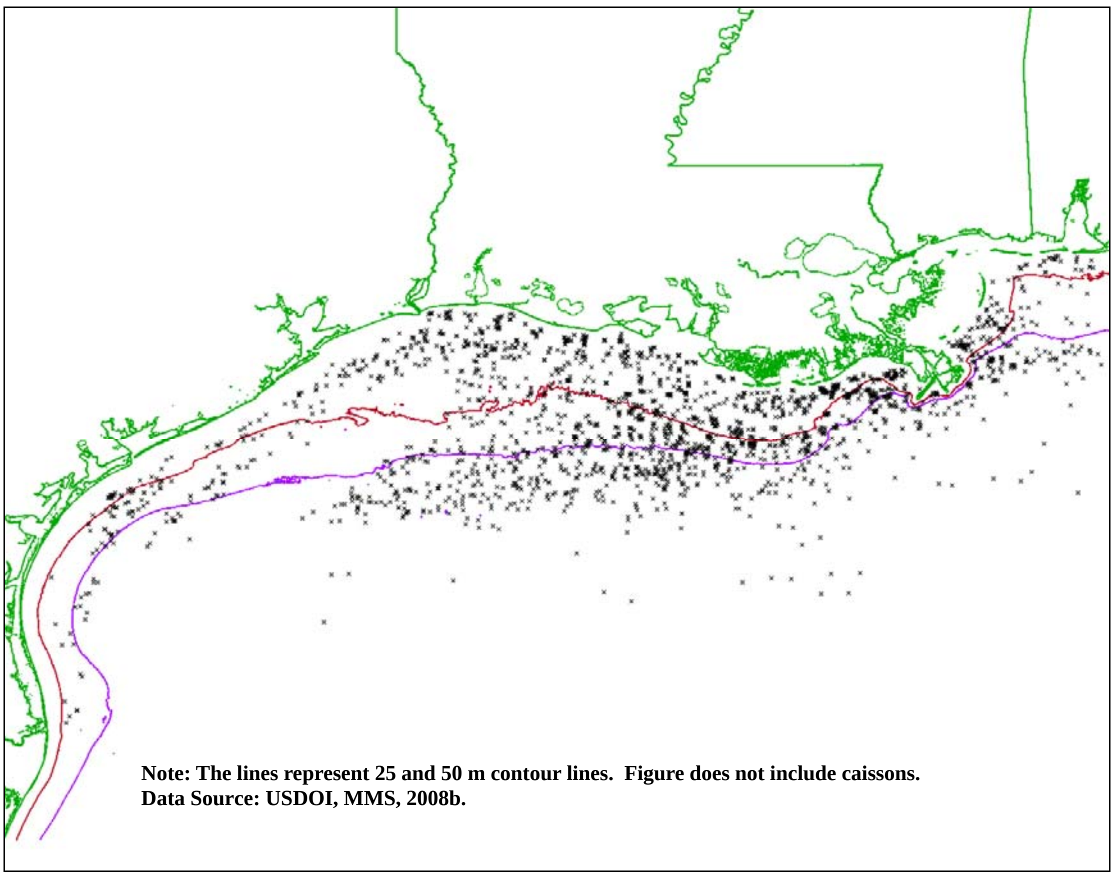


Figure E.3. Distribution of Existing Fixed Platforms by Depth (2008).

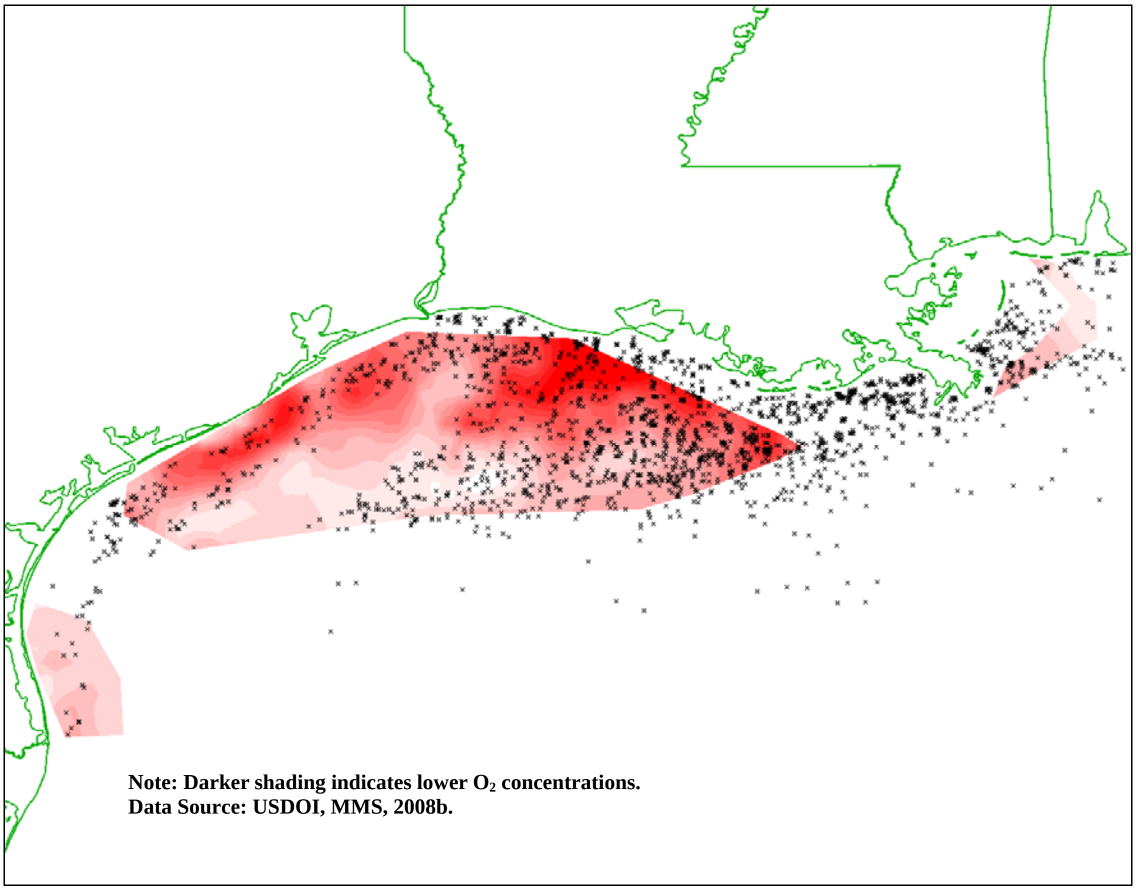


Figure E.4. Extent of the GOM Hypoxia Zone in 2007.

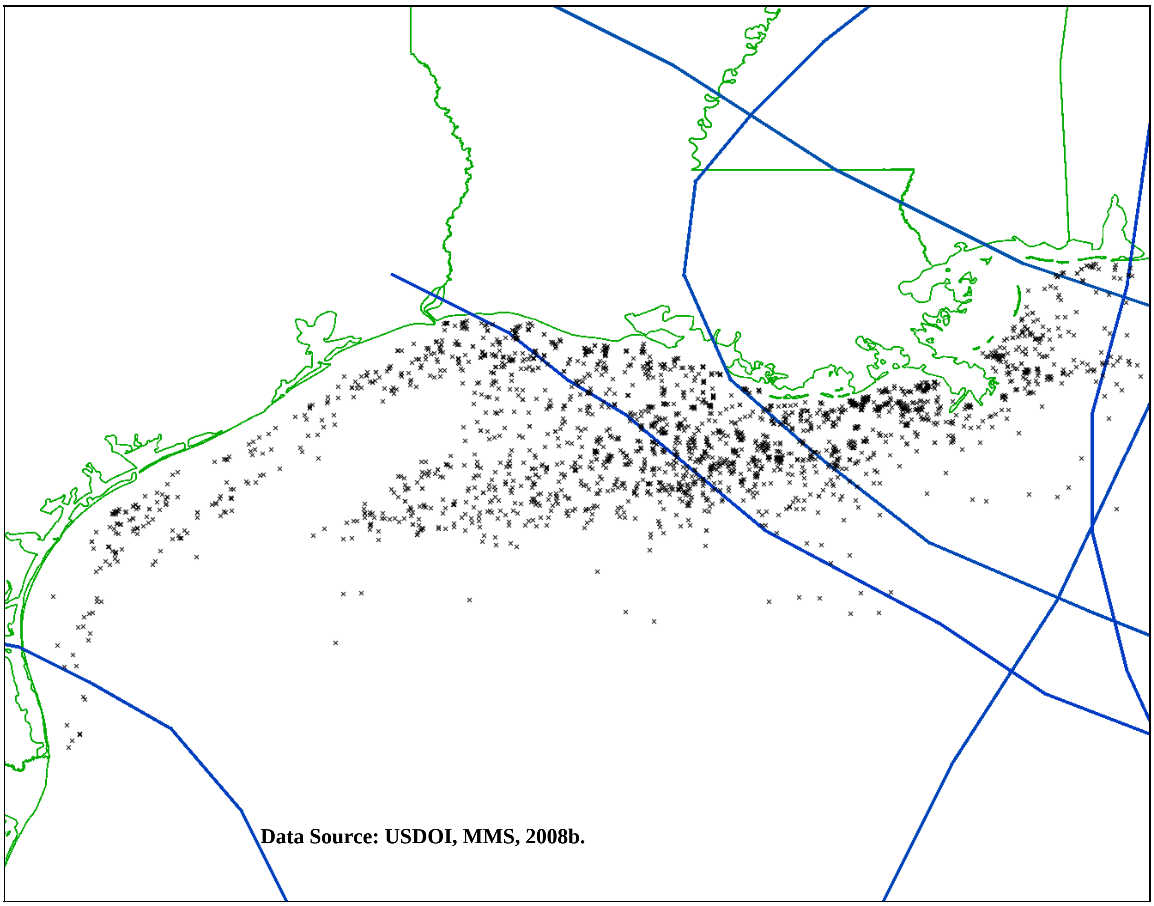
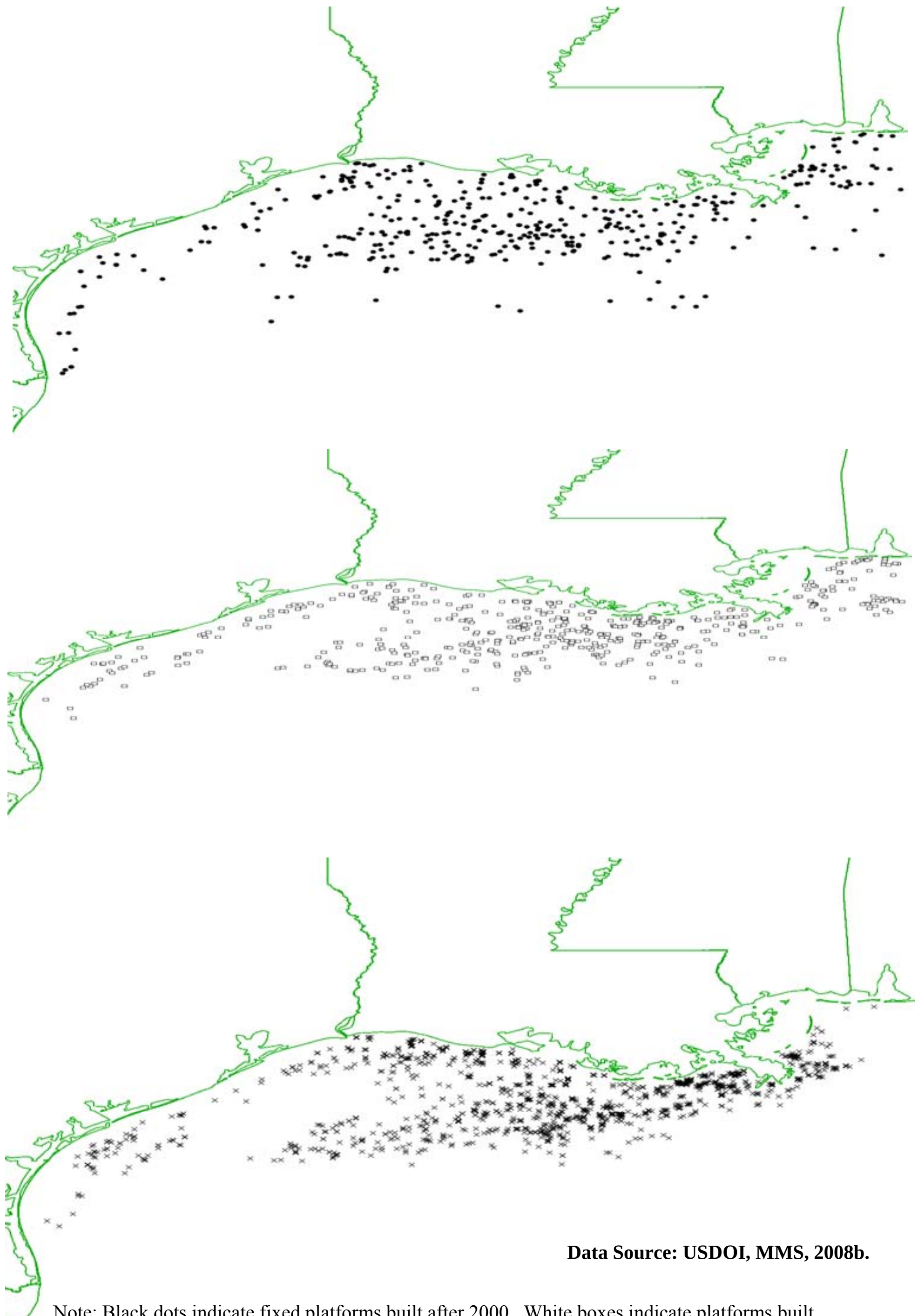


Figure E.5. Paths of Major Hurricanes Impacting the Gulf Coast from 1983 to 2004.



Note: Black dots indicate fixed platforms built after 2000. White boxes indicate platforms built between 1990 and 1999. X's indicate platforms built before 1990.

Figure E.6. Distribution of Platforms by Age.

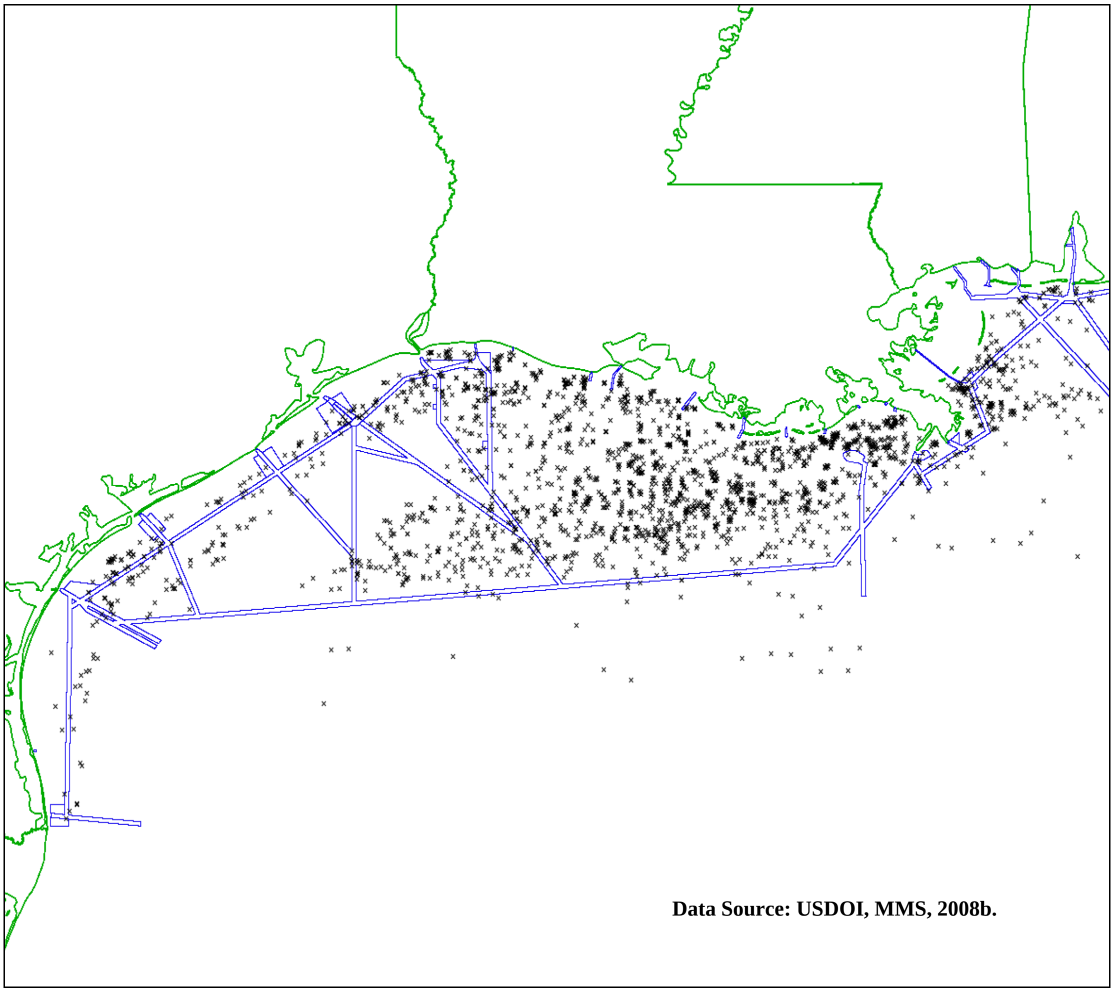


Figure E.7. Ship Traffic Lanes and Fixed Platforms.

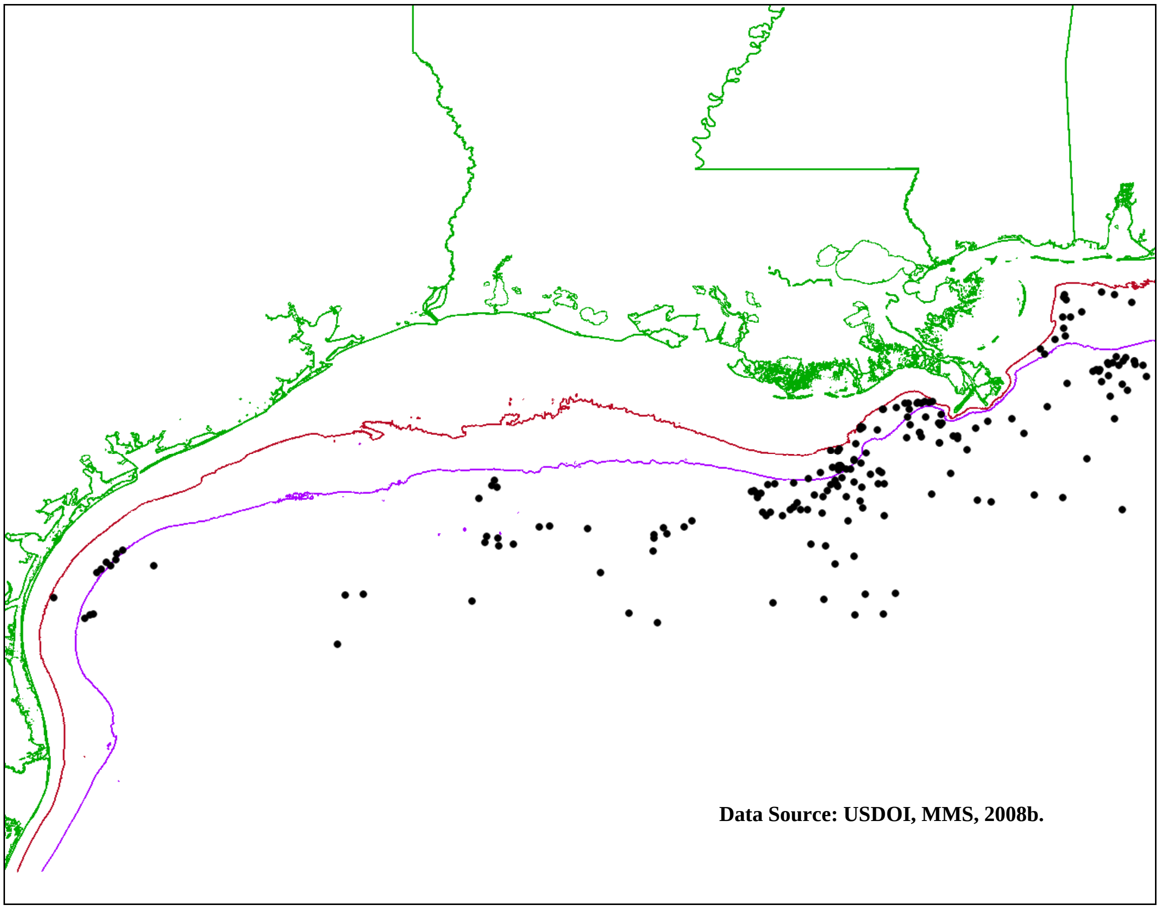


Figure E.8. Preferred Platforms for Use in OOA with 25 and 50 m Contours.

APPENDIX F.

CHAPTER 6 TABLES AND FIGURES

Table F.1.

Inflation Adjusted Cost Estimates for Offshore Mariculture

Citation	Method	Species	Break-Even Production Price ($/kg)	Profitable?
(Lisac and Muir, 2000)	Theoretical model	Sea Bass/ Seabream	7.55	Yes (With EU support)
(Lisac and Muir, 2000)	Empirical data	Sea Bass/ Seabream	6.82 (range 4.19 -11.23)	Yes
(Kam et al., 2003)	Theoretical model	Pacific Threadfin	8.76	No
(Ryan, 2004)	Theoretical model	Atlantic Salmon	2.6 -3.4	Yes
(Posadas and Bridger, 2003)	Theoretical model	Cobia	4.28	Generally No
		Red Snapper	4.28	No
		Red Drum	4.28	No
(Lipton and Kim, 2007)	Theoretical model	Rock Bream	8.51	Yes
(Kirkley, 2008)	Theoretical model	Mussels	0.77	Yes
		Sea Scallops	Not reported	Yes
		Cod	2.02	Yes
		Atlantic Salmon	2.02	Yes
		Flounder	3.53	Yes
(Jin, 2008)	Theoretical model	Cod	2.25	Yes
		Salmon	2	Yes

Note: Jin (2008) and Kirkley (2008) use the same methods and assumptions and generate similar results; these results should not be considered independent.

Table F.2.

Assumptions of Theoretical Cost Studies of OOA

Study	Species	FCR	Interest Rate (%)	Feed Price ($/mt)	Fingerling Cost ($)	Stocking Density (kg/m^3)	Final Density (kg/m^3)	Ratio Final Density: Stocking Density	Cage Cost ($/m^3)	Offshore Facilities	Survival Rate (%)
(Lipton and Kim, 2007)	Rock Bream	1.3	2.8	1,600	0.40	0.564	12.7	22.5	89	None	97
(Posadas and Bridger, 2003)	Cobia, Red Snapper, Red Drum	1.5	5	910	1.54	0.178	20-30	112.3	50	Jack up barge	80
(Kam et al., 2003)	Pacific Threadfin	2.39	10	1,250	0.27	0.109	13.32	122.2	27	None	93
(Lisac and Muir, 2000)	Sea Bass/ Seabream	2.3	5	916	0.73	0.72	16	22.2	75 (includes boats)	None	90
(Jin, 2008)	Cod	1.5	7	600	0.85	1.5	35.4	23.6	15	None	99
	Salmon	1.5	7	730	1.5	1.35	33.8	25.0	15	None	99
(Kirkley, 2008)	Flounder	1.5	7	650	2	13	25	1.9	15	None	99
Model A (this paper)	Cobia	1.5	20	1,000	2	0.012	3.78	315	20	Platform	90
Model B (this paper)	Cobia	1.5	20	1,000	2	0.1	22.5	225	20	Platform	80

Table F.3.

Summary of Basic Assumptions

	Unit	Model A			Model B		
		Pessimistic	Expected	Optimistic	Pessimistic	Expected	Optimistic
Cost of Platform	Million $	2	1.7	1.4	2	1.7	1.4
# Cages		2	4	8	2	4	8
Volume of Each Cage	m^3	39,270	39,270	39,270	39,270	39,270	39,270
Cost of Each Cage	$\$/m^3$	35	20	8	35	20	8
Cost of Vessel	1000 $	1,218	1,218	1,218	1,218	1,218	1,218
Cost of Vehicles	1000 $	235	235	235	235	235	235
Fingerling Size	kg	0.02	0.02	0.02	0.02	0.02	0.02
Initial Density	kg/m^3	0.012	0.012	0.012	0.1	0.1	0.1
Final Density	kg/m^3	3.78	3.78	3.78	15	22.5	27
Price per Fingerling	$	2.00	2.00	2.00	2.00	2.00	2.00
Transportation Cost of Each Fingerling	$	1.00	0.50	0.25	1.00	0.50	0.25
Feed Cost (Bulk Rate)	$/mt	1,000	1,000	1,000	1,000	1,000	1,000
FCR		1.7	1.5	1.3	1.7	1.5	1.3
Veterinary Costs	$/kg $/fingerling	0.033	0.033	0.033	0.25	0.25	0.25
Uneaten Feed Rate	%	15	8	1.40	15	8	1.40
Survival Rate	%	90	90	90	75	80	90
Growth Rate	kg/yr	6.5	6.5	6.5	4	5	6
Harvesting Cost	$/kg	0.088	0.088	0.088	0.088	0.088	$0.088
Ex-vessel Price	$/kg	4.44	4.88	5.55	4.44	4.88	5.55
# Workers		8	16	32	8	16	32
Annual Salary of Each Worker	$	50,000	50,000	50,000	50,000	50,000	50,000
Annual Salary of Manager	$	110,000	110,000	110,000	110,000	110,000	110,000
Annual Salary of Supervisor	$	70,000	70,000	70,000	70,000	70,000	70,000
Cost of Capital	%	30	20	10	30	20	10
Depreciation Time	years	10	10	10	10	10	10
Tax Rate	%	35	35	35	35	35	35
Inflation Rate	%	2.75	2.75	2.75	2.75	2.75	2.75
Project Life Time	years	10	10	10	10	10	10
Contingency Capital Cost	%	20	15	10	20	15	10
Efficiency Gain	%	3	5	7	3	5	7

Table F.4.

Fish Feed Prices of Top 3 Suppliers in 2007

	Nutreco	Cermaq	BioMar
Revenue (millions)	1193 EURO	5922 NOK	5000 DKK
Production (million tons)	1.300	0.847	0.700
Average Exchange Rate[a]	1.35EURO/USD	0.17 USD/NOK	0.18 USD/DKK
Average Price ($/mt)[b]	1238	1188	1285

Footnote a) Adopted exchange rate is the average exchange rate in 2007.
b) Price as of 2007.
Sources: BioMar Group, 2007; Cermaq, 2007; Nutreco, 2007.

Table F.5.

Cage Cost Estimate (2007)

Name	Type	Cost ($/m^3)[a]
Sea Station	Submersible Cage	38.36
FarmOcean	Floating Cage	87.68
SADCO Shelf	Floating Cage	98.64
Dunlop Tempest	Net-pen	21.92
Aqualine Offshore	Net-pen	8.77

Footnotes: Price inflation-adjusted to 2007.
Source: Hendrix, 2005.

Table F.6.

Calculation for Fingerling and Feed Model A

	Pessimistic	Expected	Optimistic
Number of Cages	2	4	8
Volume per Cage (m^3)	39,270	39,270	39,270
Cost of Net-Pen or Cage ($/$m^3$)	35	20	8
Growth Rate (kg/yr)	6.5	6.5	6.5
Production (kg/m^3)	3.78	3.78	3.78
Total Production(lb)	654,498	1,308,997	2,617,994
Price per Fingerling ($)	2.00	2.00	2.00
Transportation Cost ($/fingerling)	1.00	0.50	0.25
Survival Rate	90%	90%	90%
Number of Fingerlings Needed	50,748	101,497	202,994
FCR	1.70	1.50	1.30
Uneaten Feed Rate	15%	8%	1%
Feed Requirements (lbs)	1,454,441	2,371,371	3,835,240

Table F.7.

Capital Costs for Models A and B ($1,000)

	Pessimistic	Expected	Optimistic
Cost of Platform	2,000	1,700	1,400
Total Cost of Net-Pen or Cage	2,749	3,142	2,513
Land (Base Camp)	94	94	94
Permitting	118	118	118
Engineering and Legal Fees	353	353	353
Removal of Oil Production Equipment	1,000	1,000	1,000
Other Consultants	118	118	118
Building	118	118	118
Maintenance Shop	177	177	177
Loading Dock with Crane	589	589	589
Fuel Storage and Loadout Facilities	118	118	118
Camp Equipment	118	118	118
Vehicles	235	235	235
Vessels	1,218	1,218	1,218
Contingency Capital Cost	20%	15%	10%
Total Capital Costs	10,804	10,461	8,985

Table F.8.

Average Operating Costs Over 10-Year Project Lifetime ($1,000)

	Model A			Model B		
	Pessimistic	Expected	Optimistic	Pessimistic	Expected	Optimistic
Manager	129	129	129	129	129	129
Supervisor	82	82	82	82	82	82
Employees	471	942	1,883	471	941	1,883
Fingerling Cost	101	203	406	785	1,571	3,142
Fingerling Transportation	51	51	51	393	393	393
Farm Insurance	200	200	200	200	200	200
Other Insurance	129	129	129	129	129	129
Feed Costs	660	1,076	1,740	2,356	5,122	11,184
Veterinary	22	44	89	98	196	393
Harvesting	26	52	105	104	276	746
Fuel	59	118	235	118	118	118
Equipment Maintenance	294	294	294	294	294	294
Platform Maintenance	235	235	235	235	235	235
Surety Bond	200	200	200	200	200	200
Operations	353	353	353	353	353	353
Other	88	88	88	88	88	88
Total	3,102	4,198	6,221	6,037	10,330	19,570

Table F.9.

Net Present Value Results, Model A

	Pessimistic	Expected	Optimistic
Ex-Vessel Price ($/kg)	4.4	4.8	5.5
Production (kg)	294,524	589,048	1,178,097
Total Revenue ($ million)	1.295	2.880	6.545
Accumulated Cash Flow from Operating Activities ($ million)	-6.13	-1.08	12.99
Net Present Value ($ million)	-12.87	-11.27	-1.54

Table F.10.

Net Present Value Results, Model B

	Pessimistic	Expected	Optimistic
Ex-vessel price ($/kg)	4.44	4.88	5.55
Production (kg)	1,178,100	3,141,600	8,482,320
Total Revenue (($ million)	5.230	15.331	47.076
Accumulated Cash Flow from Operating Activities ($ million)	-4.608	38.969	205.961
Net Present Value ($ million)	-9.524	8.594	120.1

Table F.11.

Comparison of Financial Performances of Expected Scenario (Model A) and Rent Scenario ($1,000)

	Expected	Rent
Capital Costs	10,461	7,064
Operating Cost in the First Fiscal Year	4,198	4,333
Accumulated Cash Flow from Operating Activities ($ million)	-1.077	-1.905
Net Present Value ($ million)	-11.27	-7.951

Table F.12.

Break-Even Analysis Showing the Value for Parameters at Which NPV Is Zero

Model	Scenario	Original NPV Positive?[a]	Production (kg/m^3)	Growth Rate (kg/year)	Cost of Capital (%)	Product Price ($/kg)	FCR	Platform Cost (Million $)	Survival Rate	Fingerling Cost ($)
A	Rent	No	57.3		NA[b]	10.17	NA		NA	NA
A	Optimistic	No	20.88*		6.3	5.88*	0.95	NA	NA	NA
A	Expected	No	66		NA	11.91	NA	NA	NA	NA
A	Pessimistic	No	255		NA	12.17	NA	NA	NA	NA
B	Optimistic	Yes	5.5*	1.22	190	2.01	5.76	140	18%*	26.5
B	Expected	Yes	14*	3.52*	39.4	3.87*	2.5*	10.5	56%*	6.65*
B	Pessimistic	No	35*	9.35	NA	8.82	NA	NA	NA	NA

a. The column "Original NPV Positive?" is meant as a reference to determine if the NPV decreased (Yes) or increased (No) with the change.

* Values with * suggest that the necessary parameter value is realistic.

b. NA suggests that any plausible value is not capable of making NPV positive. For example, NA might indicate a survival rate of greater than 100% is needed. Blank values suggest that the value is not incorporated into the model.

Table F.13.

Sensitivity Analysis of Model B, Expected Case

	Unit	Slope (change in NPV/change in unit)
Growth Rate	kg/year	5,819,900
Platform Cost	$	-0.98
Cage cost	$\$/m^3$	-154,135
Survival	%	363,744
Contingency capital cost	%	-7,760,479
Product prices	$/kg	8,561,196
Fingerling cost	$	-1,844,576
FCR		-8,019,896
Initial stocking density	kg/m^3	240,269,164
Insurance Premium	$	-2.34

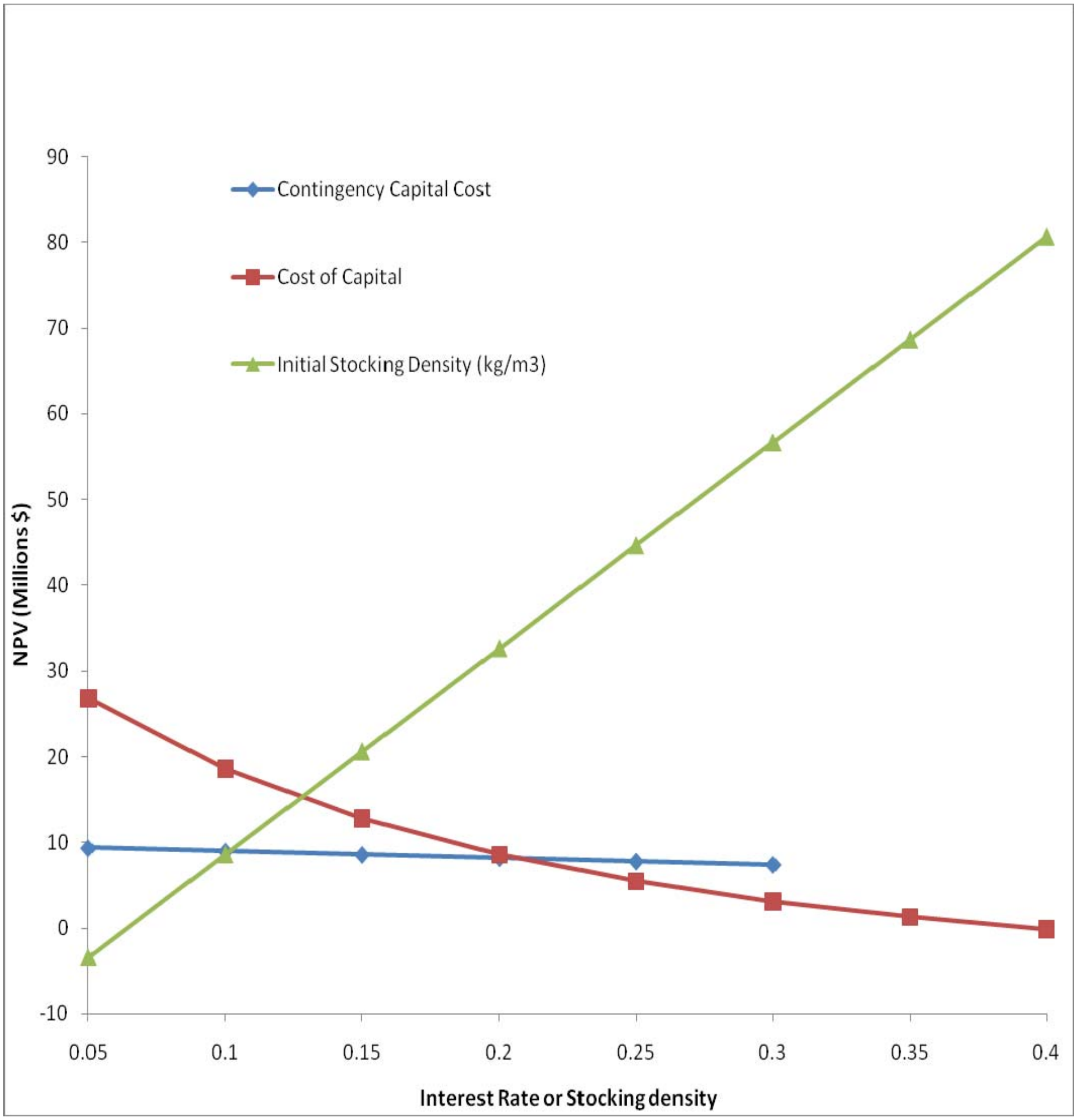


Figure F.1. Sensitivity of NPV to Changes in Contingency Capital Cost, Cost of Capital, and Initial Stocking Density. Model B, Expected Case.

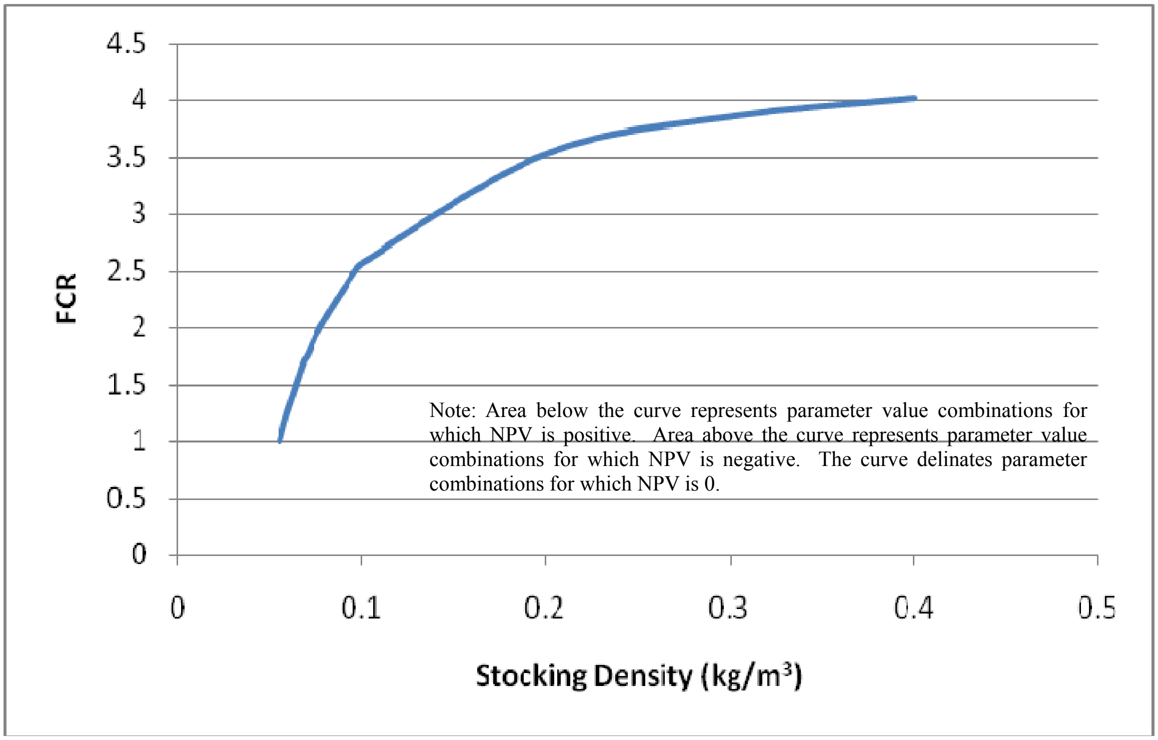


Figure F.2. Relationship Between Stocking Density and FCR in Model B, Expected Scenario.

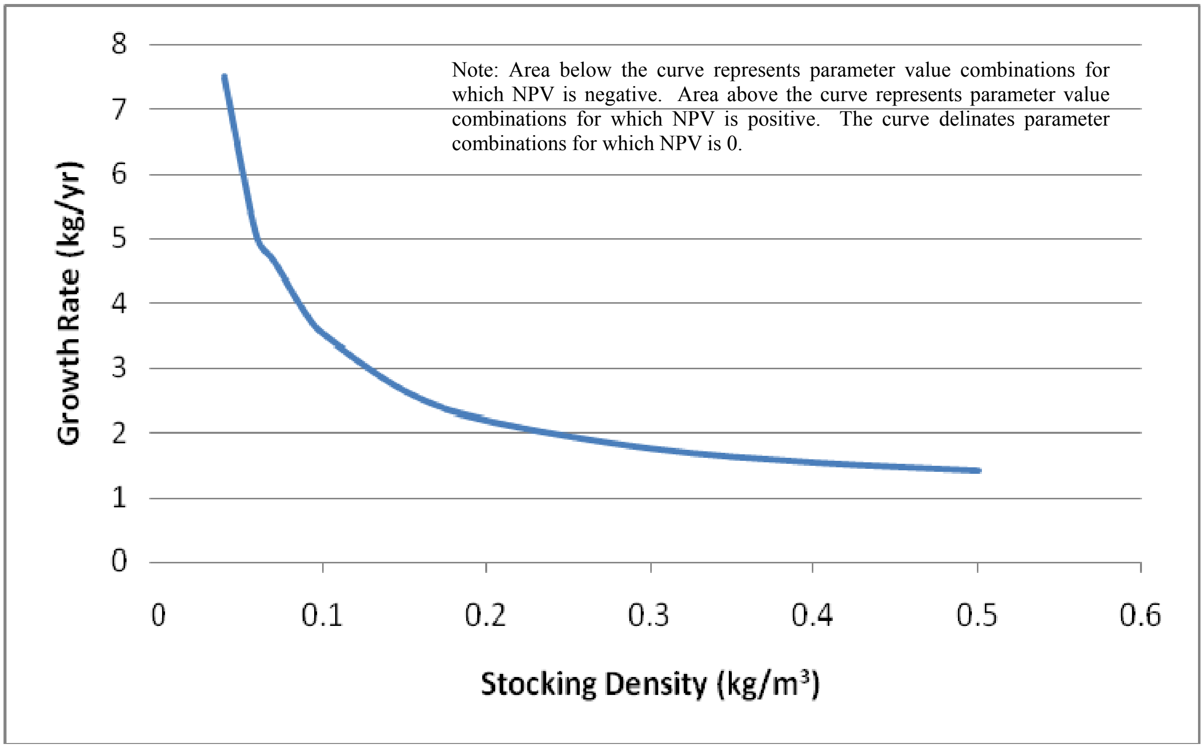


Figure F.3. NPV Break-Even Relationship Between Stocking Density and Growth Rate in Model B, Expected Scenario.

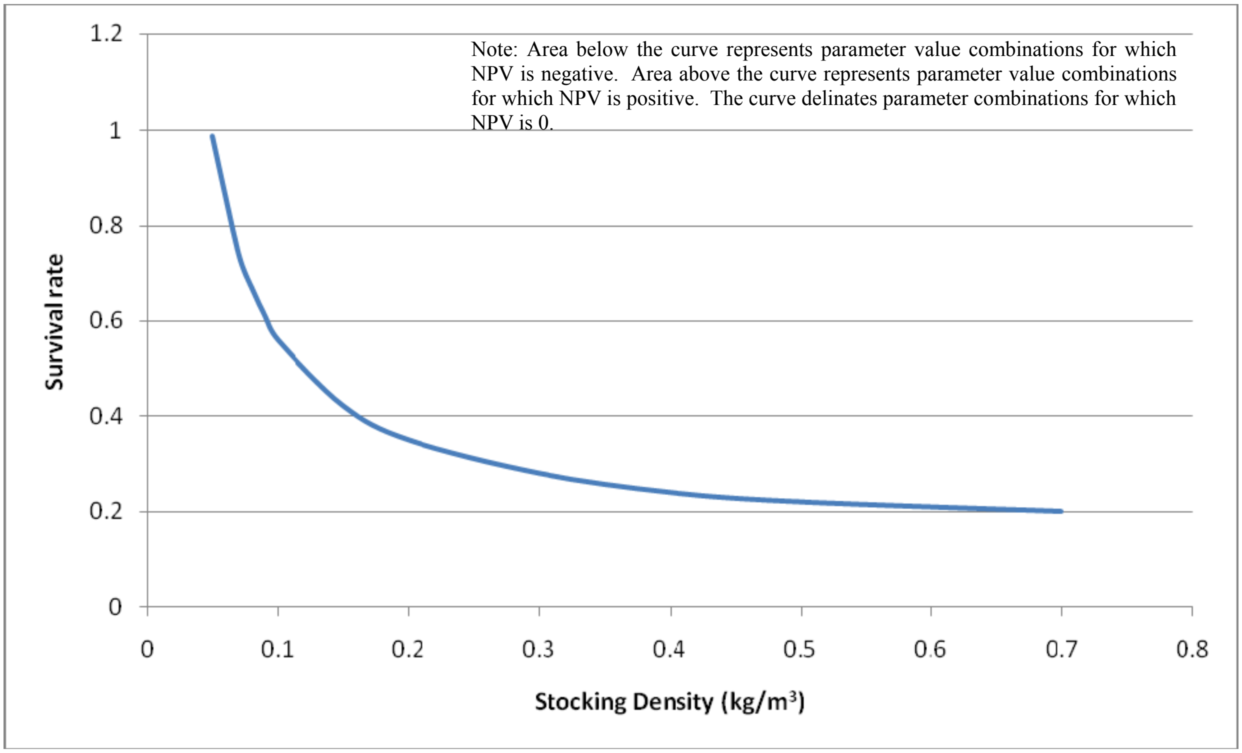


Figure F.4. NPV Break-Even Relationship Between Stocking Density and Survival Rate in Model B, Expected Scenario.

APPENDIX G.

CHAPTER 7 TABLES AND FIGURES

Table G.1.

Operational Commercial Offshore Wind Farms in Europe as of August 2008

Wind Farm	Year Built	Capacity (MW)	Depth (m)	Developer	Foundation Type	Turbine Size (MW)	Distance to Shore (km)	Sources[a]
Vindeby	1991	5	3.5	SEAS	gravity	0.45	1.5	1, 3, 9, 4
Lely	1994	2	7.5	Energie Nord West	mono	0.5	0.8	1, 3, 6, 1, 9, 12, 4
Tuno Knob	1995	5	4	Midtkraft		0.5	3	1, 3, 5, 12, 4
Dronten	1996	11	1.5	Nuon	mono	0.6	0.03	1, 3, 8, 9, 12
Bockstigen	1997	3	6		mono	0.55		1, 3, 4
Blyth	2000	4	8.5	Nuon, Shell, E.ON		2	1	1, 3, 4
Middlegrunden	2001	40	6	Energie E2	gravity	2	2	1, 3, 4, 15
Utgrunden	2001	10	8.6	Vattenfall	mono	1.425		1, 3, 4, 12
Yttre Stengrund	2001	10	8	Vattenfall	mono	2		1, 3, 4, 5
Horns Rev	2002	160	10	Vattenfall	mono	2	14	1, 3, 6, 9, 12
Frederikshaven	2003	10	4		1 suction, 3 mono	3	0.2	1, 9, 12
Nysted	2003	158	7.75	DONG	gravity	2.3	10	1, 12
Samso	2003	23	20		mono	2.3	3.5	1, 3, 5
North Hoyle	2003	60	12	Npower	mono	2	7	1, 12
Ronland	2003	17.2	1			2.3	0.1	1, 3
Scroby Sands	2004	60	16.5	E.ON	mono	2	2.5	1, 14
Arklow	2004	25	3.5	Airtricity	mono	3.6	10	1, 3
ems emden	2004	4.5	3	Enova		4.5	0.04	1, 13
Kentish Flats	2005	90	5	Vattenfall	mono	3	10	1, 12
Barrow	2006	90	17.5	DONG	mono	3	7.5	1, 5, 6, 9
Egmond aan Zee	2006	108	18	Nuon	mono	3	10	1, 14
Rostock	2006	2.5	2			2.5	0.5	1, 9, 12
Burbo Bank	2007	90	5	DONG	mono	3.6	6.5	1, 12
Beatrice	2007	10	45	Talisman	jacket	5	22	12
Lillgrund	2007	110	7	Vattenfall	gravity	2.3	10	6
Q7	2007	120	21.5	Econcern	mono	2	23	16

Footnote: (a) 1= Lemming et al., 2007; 3= Beurskens and Noord, 2003; 4= Barthelmie and Pryor, 2001; 5= Power-Technology, 2008; 6= Vattenfall, 2008; 8= DONG Energy, 2008; 9=A2sea, 2008; 10= IEA, 2005; 11= Airtricity, 2008; 12=OffshoreWindEnergy.org, 2007; 13= Enova, 2008; 14= Gerdes et al., 2007. 15= Larsen et al., 2005; 16=Econcern, 2008.

Table G.2.

Approved Offshore Wind Farms in Europe as of May 2008

Name	Country	Capacity (MW)	Number of Turbines	Turbine	Distance to Shore (km)	Status	Developer
Thornton Bank	Belgium	300	60	RePower 5 MW	28	Under Construction	C-Power
Belwind	Belgium	330	110	Vestas V90	42	Approved	ECONCERN/Evelop
Eldepasco	Belgium	180-252	36		38	Approved	
Cote d' Albatre	France	105	21	Multibrid M5000	6	Under Construction	ENERTRAG
Rodsand II	Denmark	200	92		2	Approved	E.ON.
Horns Rev II	Denmark	200	91		27	Under Construction	DONG
London Array	England	1,000	341	various	20	Approved	DONG Energy / Shell Wind Energy / E.On
Inner Dowsing	England	90	27	Siemens	5	Under Construction	Centrica Renewable Energy Ltd
Lynn	England	97	30	Siemens	5	Under Construction	Centrica Renewable Energy Ltd
Rhyl Flats	England	90	25	3.6 MW	8	Under Construction	Npower renewables
Solway Firth (Robin Rigg)	England	180	60	3 MW	10	Under Construction	E.ON UK Renewables
Greater Gabbard	England	500	140	Siemens SWT 3.6	26	Approved	Airtricity
Gunfleet Sands	England	172	48	Siemens SWT 3.6	7	Approved	DONG Energy
Scarweather Sands	England	100	30	3.6 MW	6	Approved	DONG Energy/ E.ON UK
Thanet	England	300	83		11	Approved	Warwick Energy
Amrumbank West	Germany	400	80	5 MW	36	Approved	Amrumbank West GmbH
Borkrum-West II	Germany	400	80	Multibrid M5000	45	Under Construction	
Alpha Ventus	Germany	60	12	Multibrid M5000	45	Under Construction	
Bard Offshore	Germany	400	80	5 MW	89	Approved	Bard Engineering GmbH
Gode Wind	Germany	400	80		33	Approved	Plambeck Neue Energien AG
Global Tech I	Germany	400	80		93	Approved	Nordsee Windpower GmbH
Nordsee Ost	Germany	1,250	80		30	Approved	WINKRA Offshore Nordsee Planungs- und
Dan Tysk	Germany	400	80		70	Approved	GEO mbh
Baltic I	Germany	57.5	21	2.0 - 5.0 MW	15	Approved	Offshore Ostsee Wind AG

Table G.2.

Approved Offshore Wind Farms in Europe as of May 2008 (continued)

Name	Country	Capacity (MW)	Number of Turbines	Turbine	Distance to Shore (km)	Status	Developer
Kriegers Flak	Germany	320.5	80	3.6 - 5.0 MW	31	Approved	Offshore Ostsee Wind AG
Hochsee Windpark, He dreiht	Germany	400	80		85	Approved	EOS Offshore AG
Hochsee Windpark Nordsee	Germany	400	80		90	Approved	EOS Offshore AG
Offshore- Windpark Nordergründe	Germany	125	25		13	Approved	
Nördlicher Grund	Germany	up to 2,010	up to 402		86	Approved	GEO mbH, renergys GmbH
Meerwind	Germany	1,350	270	3.6 - 5.0 MW	15-80	Approved	Windland Energie
Sandbank 24	Germany	4,720	980	Up to 5 MW	90	Approved	Sandbank 24 GmbH
Wilhelmshaven	Germany	4.5	1		<10 m	Approved	Winkra-Energie GmbH
Offshore NorthSea Windpower	Germany	1,255	251		39	Approved	Enova Offshore
Arkona Becken Südost	Germany	1,005	201		35	Approved	AWE- Arkona-Windpark- Ent-
GEOFReE	Germany	25	5			Approved	GEO mbh
Ventotec Ost 2	Germany	600	200		104	Approved	Arcadis Consult GmbH
Borkum Riffgrund West	Germany	280	80		50	Approved	Energien AG
Offshore- Bürger-Windpark Butendiek	Germany	240	80		37	Approved	OSB Offshore
Borkum Riffgrund	Germany	231	77		34		Plambeck Neue Energien AG

Source: DENA, 2008; The Crown Estate, 2008; OffshoreWindEnergy.org, 2007; Michel et al., 2007.
Note: Table does not include planned but not yet approved wind farms.

Table G.3.

Distribution of Offshore Wind Farms by Country as of August 2008

Country	Number wind farms	Capacity (MW)	% Capacity	Planned capacity (MW)
Denmark	8	418	23	400
UK	9	674	37	2,529
Sweden	4	133	7	
Netherlands	4	241	13	
Ireland	1	25	1.3	
Germany	2	7	0.3	16,733
Belgium	1	300	16.7	810
Total	29	1,798		

Source: Tables G.1 and G.2.

Table G.4.

Proposed Offshore Wind Projects in the U.S. as of August 2008

Developer	Wind Park	Location	Number Turbines	Project Size (MW)	Depth (m)	Distance to Shore (km)	Status
EMI	Cape Wind	Cape Cod	130	450	0.15 - 18	10.5	Draft EIS completed
WEST	Galveston Offshore Wind	Galveston	50-60	150	16	11	Lease Signed
Deepwater Wind	Plum Island	Long Island	2-3	10	4-11	0.5	Awaiting COE approval
FPL	Long Island Wind Park	Long Island	40	150	15-20	5.8	On-hold
SRE/Babcock and Brown	Padre Island	South Texas	100+	500			Cancelled
Patriot Renewables	South Coast Wind	Buzzards Bay, Massachusetts	90-120	300	Under 20	2	Conducting State EIS
BlueWater Wind		Delaware		450		19	Agreement signed
Southern Company		Georgia	3-5	10			Expressed interest to BOEMRE in non-commercial lease
Hull Municipal	Hull Offshore Wind	Massachusetts	4	12-20	7-14	2	Applied for State permit
Deepwater Wind		Rhode Island	~100	~385			Agreement under negotiation
Deepwater Wind	Garden State Offshore Energy	New Jersey	96	350		~30	Recently Awarded
Radial Wind	Radial Wind Park	Lake Michigan	390	1,950		25	

Source: Musial and Ram, 2008.

Table G.5.

Economic Incentives for Offshore Wind Development in Europe

	Denmark	UK	Germany	Netherlands	Belgium
Feed in Price	Negotiable: recently 13.2 €/kWh		9.1 €/kWh	Premium likely to be over 0.28 €/kWh	
Tax Exemptions	Exempt from 20 €/tonne carbon tax	4.3 p/kWh		Yes	Yes
Renewable Energy Credits		~ 5 p/kWh			0.108 €/kWh for first 216 MW
Other Subsidies		Construction grants			Government pays some of cable costs, resource assessment costs
Renewable Goal for 2020	30%	15%	18%	14%	13%

Source: EREC, 2007a and b.

Table G.6.

Regulations for Leasing Land for Offshore Wind Development in Europe and the U.S.

Nation	Denmark	Germany	UK	Texas	U.S.
Fee	None	None	One time lease fee of up to £500,000	3.5 to 5.5% royalty during operation	2% of gross revenue
Term	25 years	25 years	Up to 50 years	30 years	30 years
Competition	lowest feed-in price	first-come first-served	quality of proposal	monetary benefit to state	monetary benefit to state
Selection of Sites by Regulators	Yes	No	Yes	Yes	Mixed

Sources: Peloso, 2006; BSH, 2008; Texas General Land Office, 2007a and b; USDOI, BLM, 2006; The Crown Estate, 2008.

Table G.7.

Ten Largest Manufacturers of Turbines in 2006

Company	Nation	Market Share
GE	U.S.	15.3%
Vestas	Denmark	27.4%
Enercon	Germany	14.2%
Gamesa	Spain	15.5%
Suzlon	Netherlands	7.5%
Siemens	Germany	7.1%
Nordex	Germany	3.3%
REPower	Germany	3.2%
Mitsubishi	Japan	1.0%
Goldwind	China	2.8%

Source: WWEA, 2007.

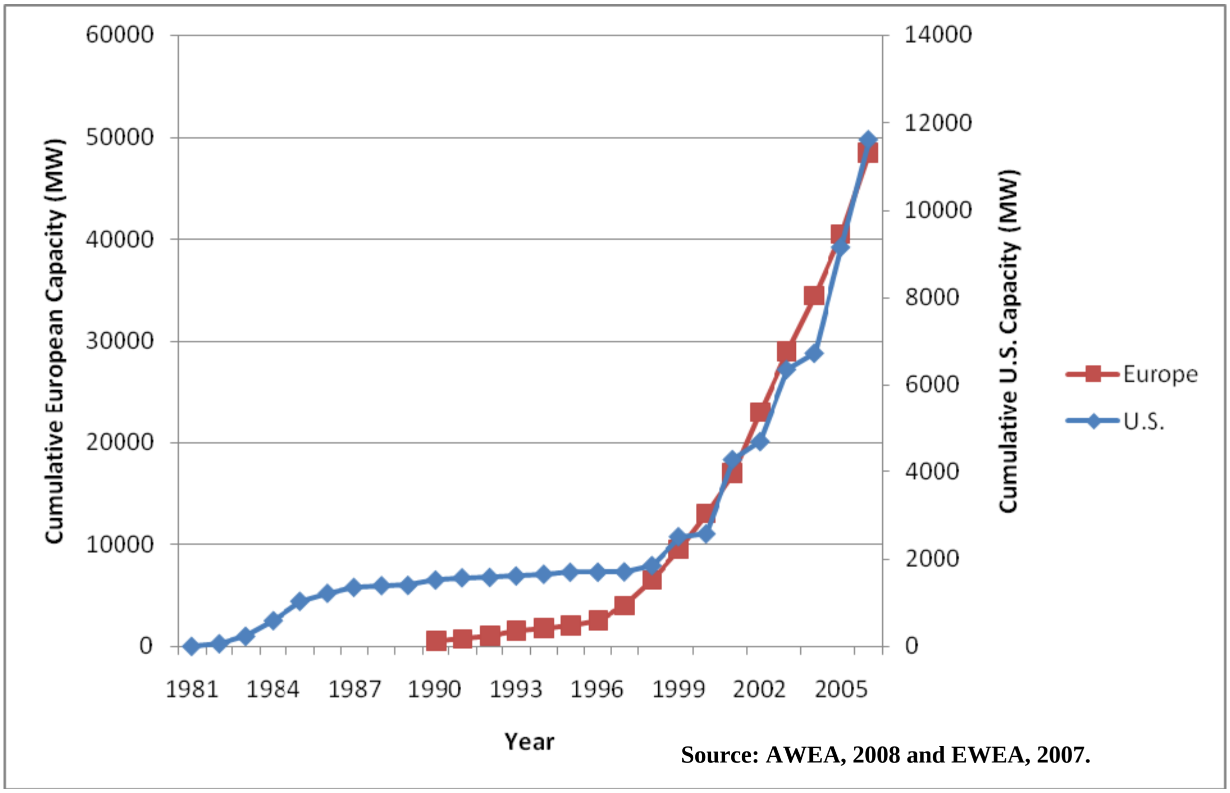


Figure G.1. Cumulative Capacity of the U.S. and European Onshore Wind Industry.

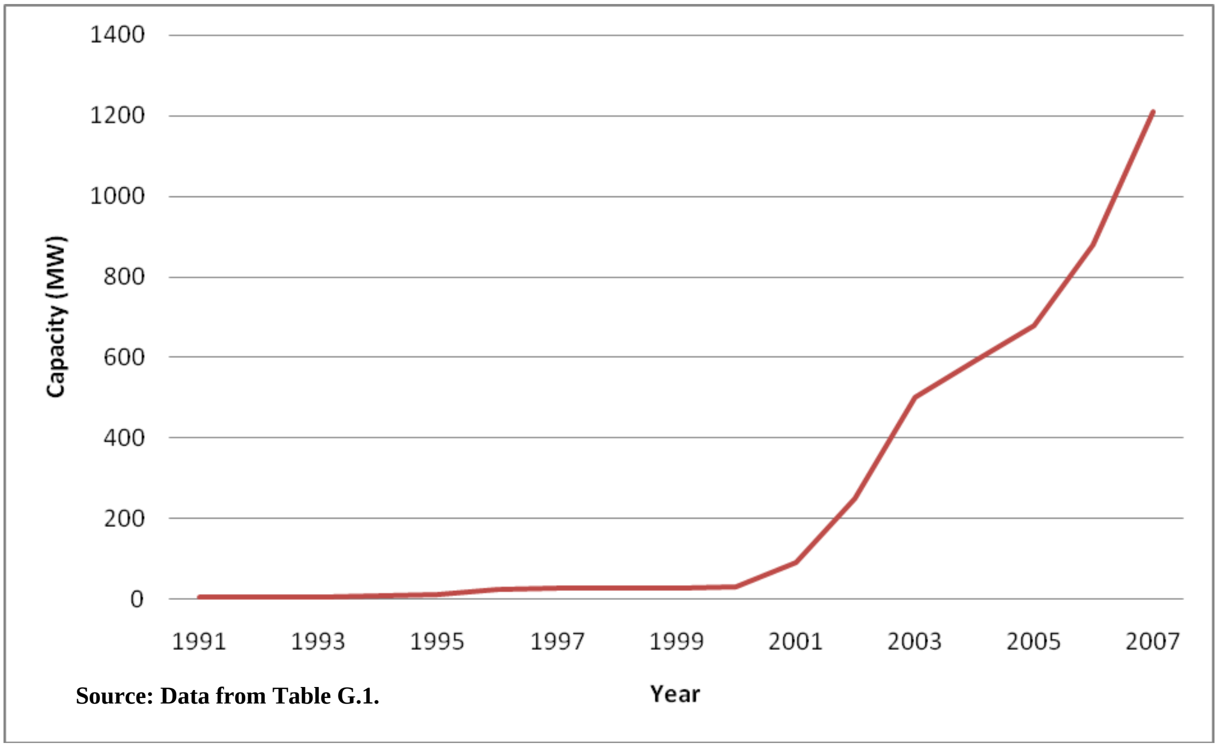


Figure G.2. Cumulative Capacity of European Offshore Wind Farms.

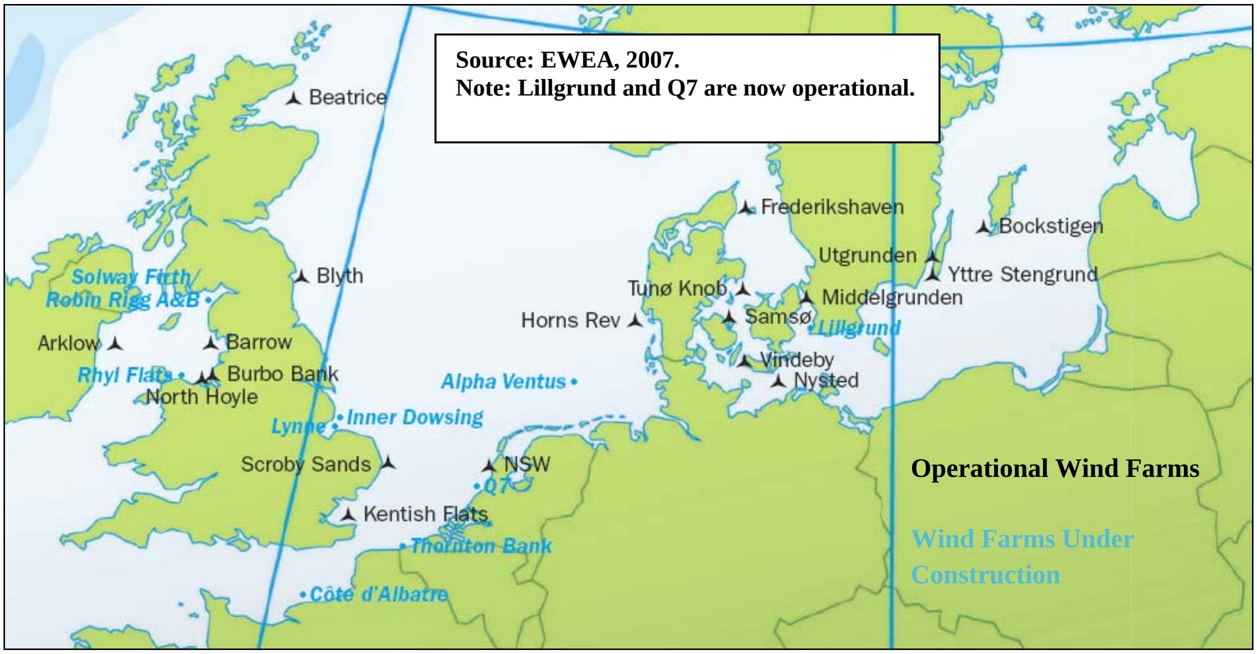


Figure G.3. Operational and Planned Offshore Wind Farms as of 2007.

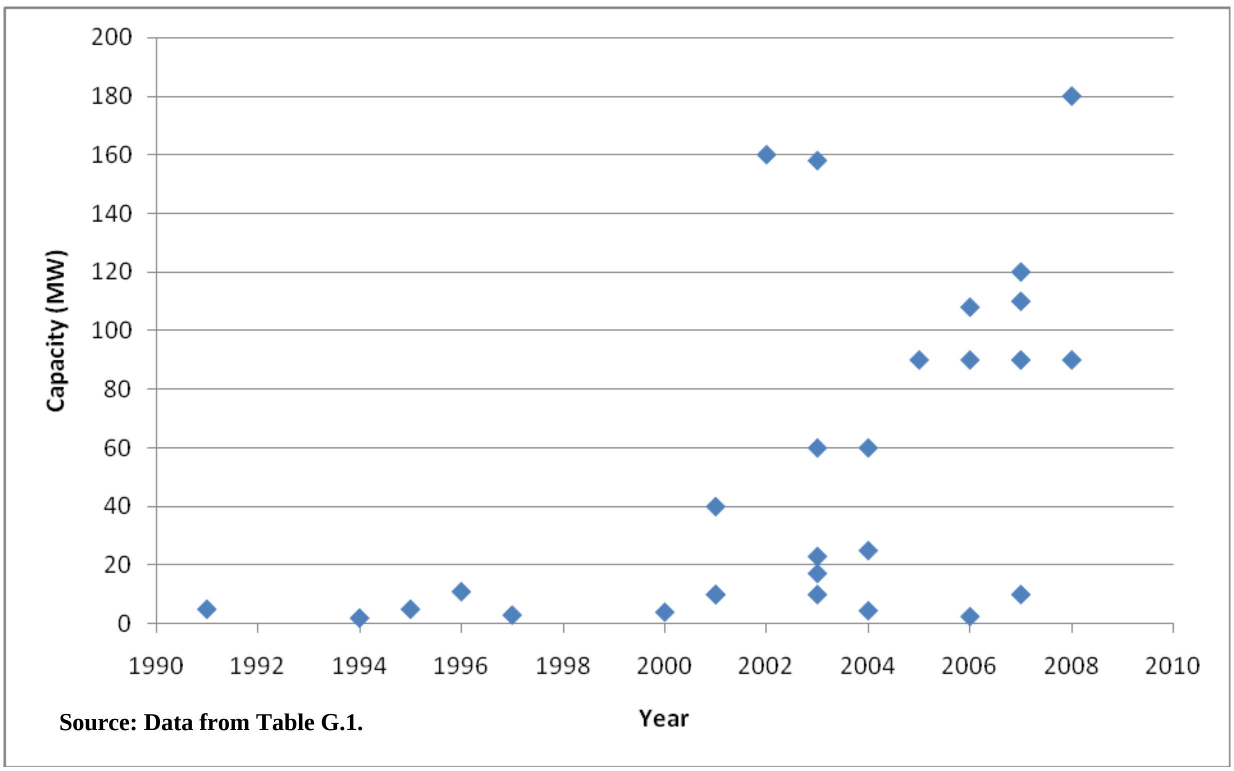
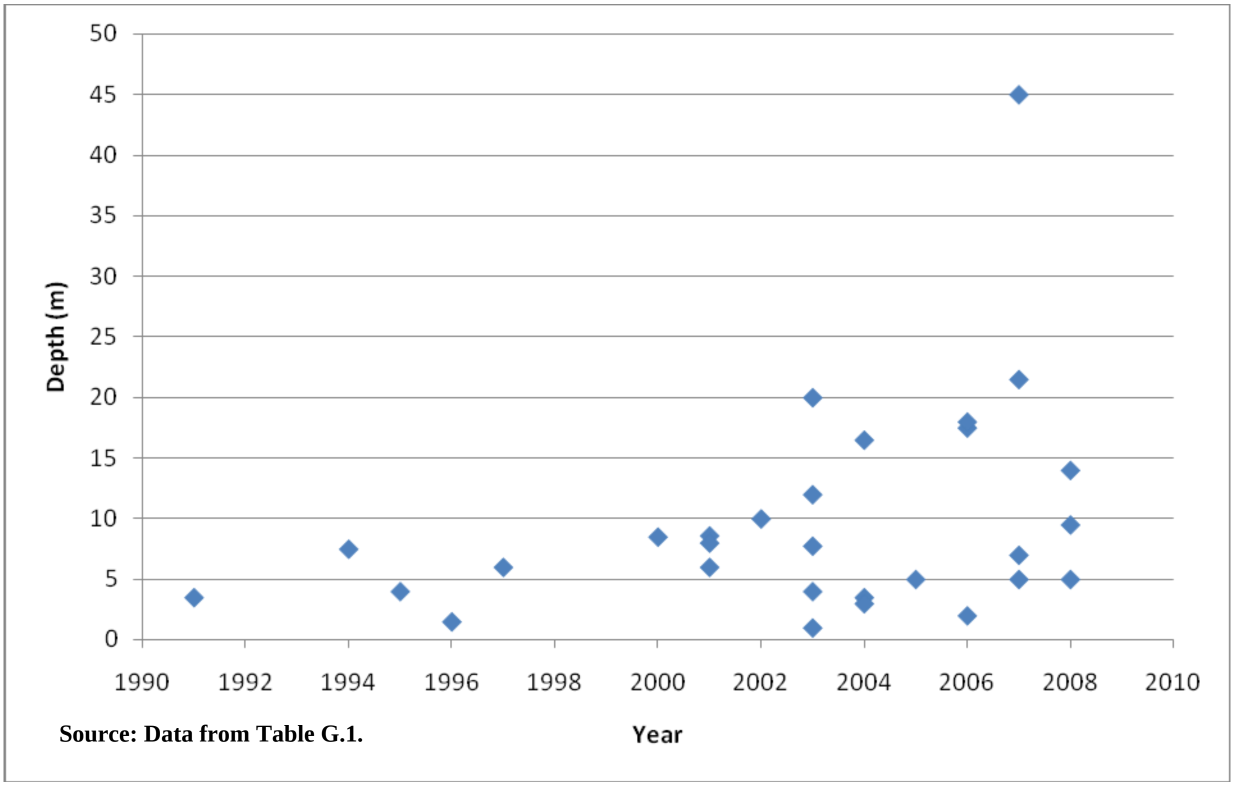
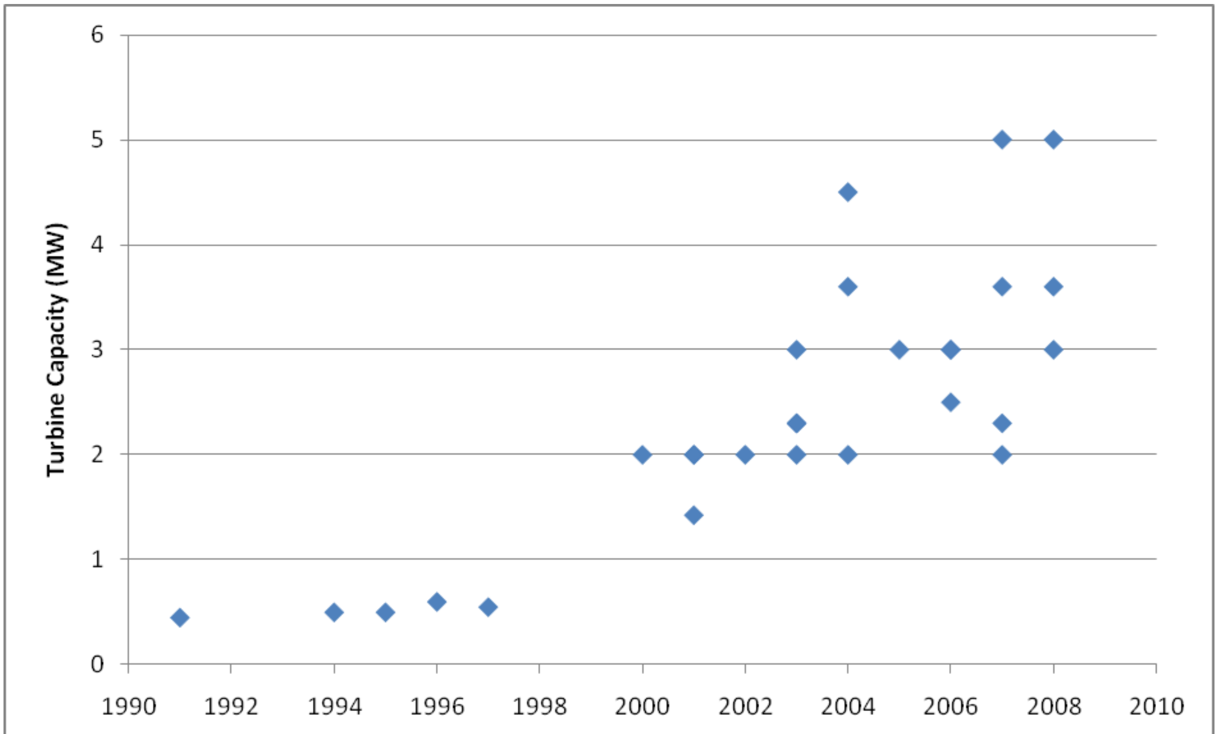


Figure G.4. Increasing Size of Development of European Offshore Wind Farms Over Time.



Source: Data from Table G.1.

Figure G.5. Increasing Depth of European Offshore Wind Farms Over Time.



Source: Data from Table G.1.

Figure G.6. Increasing Turbine Capacity of European Offshore Wind Farms Over Time.

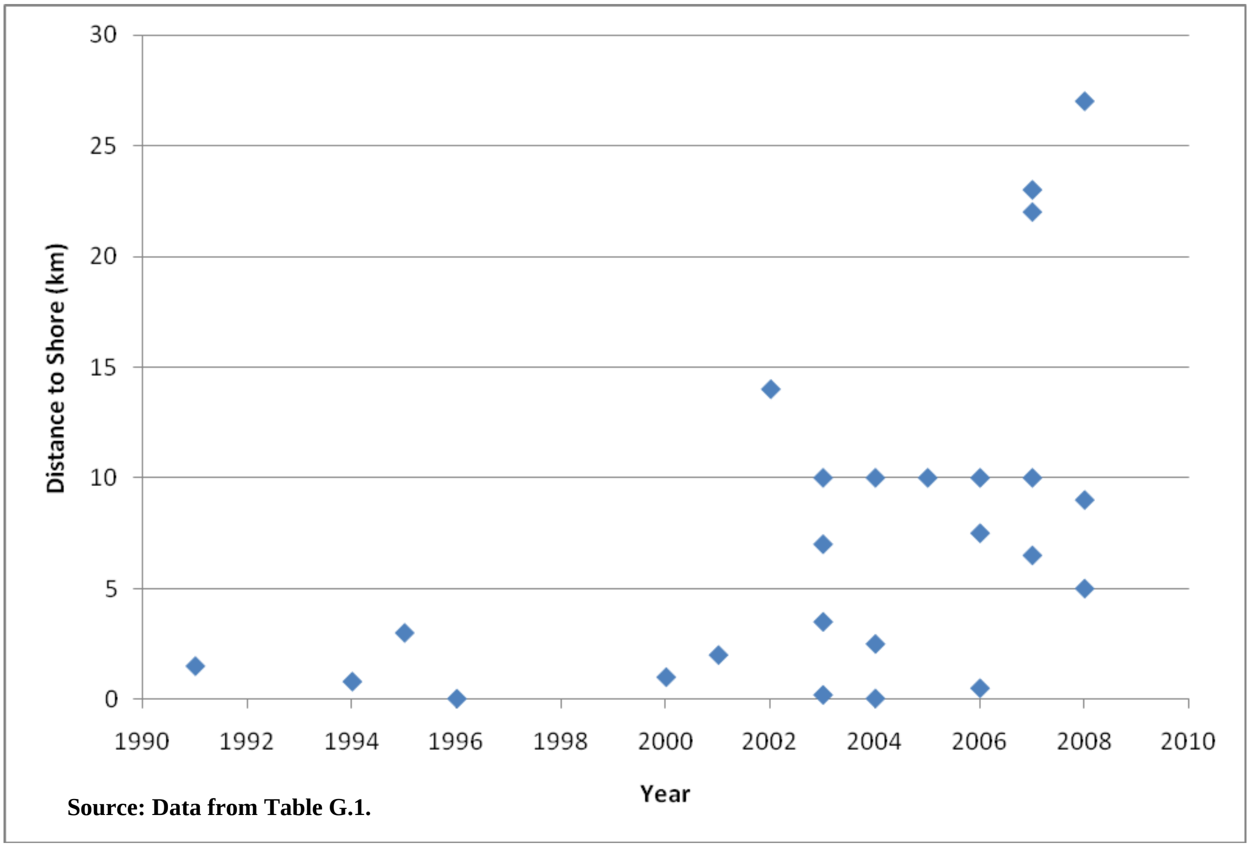


Figure G.7. Increasing Distance to Shore of European Offshore Wind Farms Over Time.

Figure G.8a. Rows of Turbines at Nysted with Sailboat in Foreground.

Figure G.8b. Row of Turbines at North Hoyle Showing Transition Piece Painted Yellow for Navigational Purposes.

Figure G.8c. Grid Arrangement of Horns Rev Wind Farm.

Figure G.8d. Aerial View of Kentish Flats.

Figure G8e. Burbo Bank Offshore Wind Farm.

Figure G.8f. Scroby Sands.

Figure G.9. Middlegrunden Offshore Wind Farm Showing Curved Arrangement.

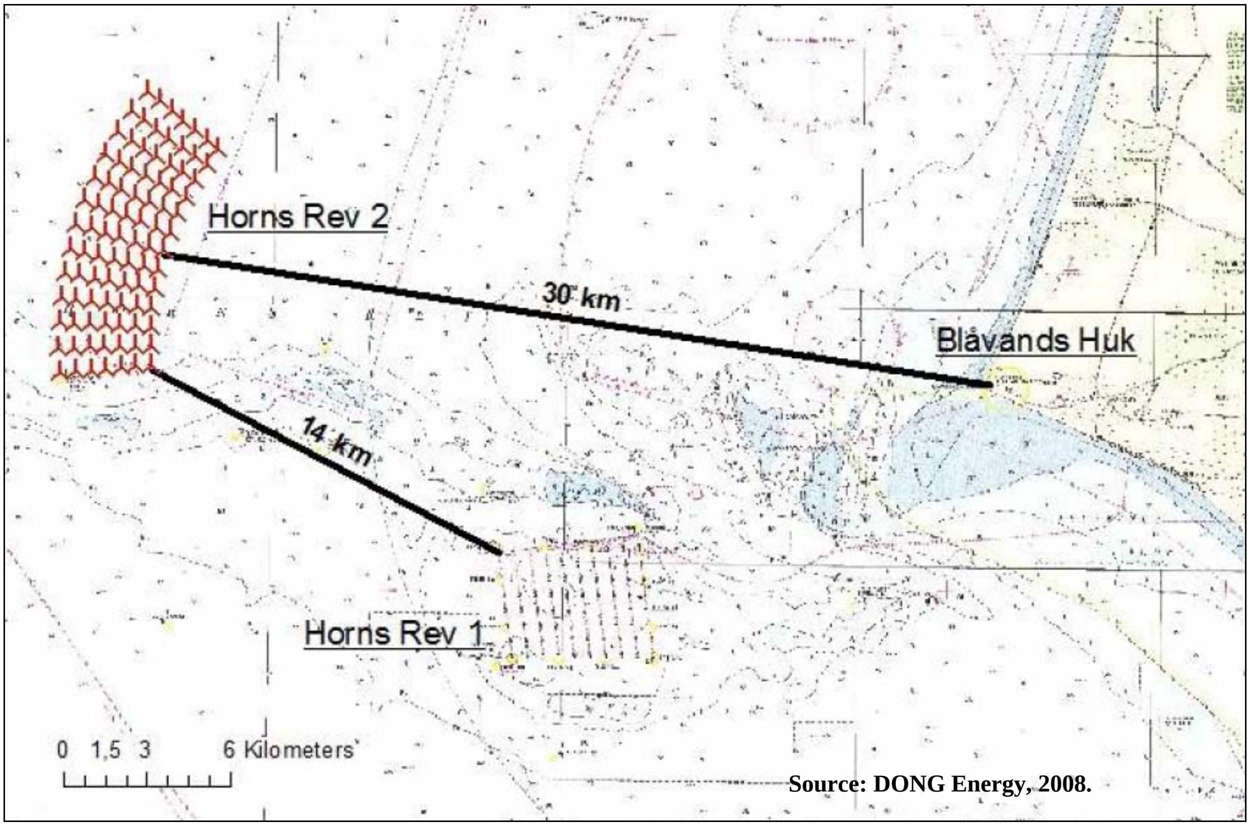


Figure G.10. Layout of Horns Rev II Wind Farm.

Figure G.11. Electrical Service Platform at Lillgrund.

Source: Elsam, 2008.

Figure G.12. Monopile after Installation by Jack-Up Barge Resolution at Kentish Flats.

Source: Elsam, 2008.

Figure G.13. Nacelle and Blades Being Lifted In Bunny Ear Configuration at Kentish Flats.

Figure G.14. Beatrice Jacket Foundation. Note People in Foreground for Scale.

Figure G.15. Sinking of a Jacketed Foundation for the Beatrice Project.

Figure G.16. Lifting of the Beatrice Turbine and Foundation.

Source: Talisman Energy, 2008.

Figure G.17. Connection of the Beatrice Turbine Tower and Foundation.

Figure G.18. Gravity Foundations at Nysted.

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Figure G.19. Monopile for Use at Kentish Flats.

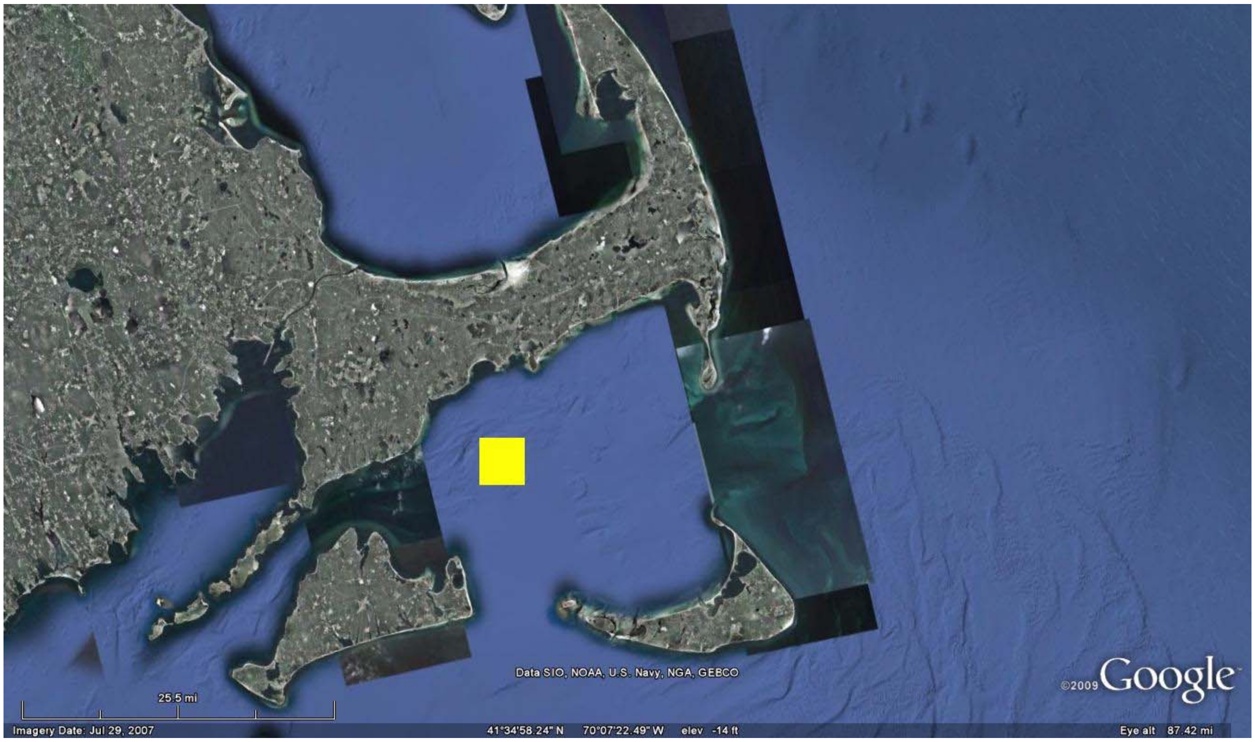


Figure G.20. Approximate Location of Cape Wind Offshore Wind Farm.

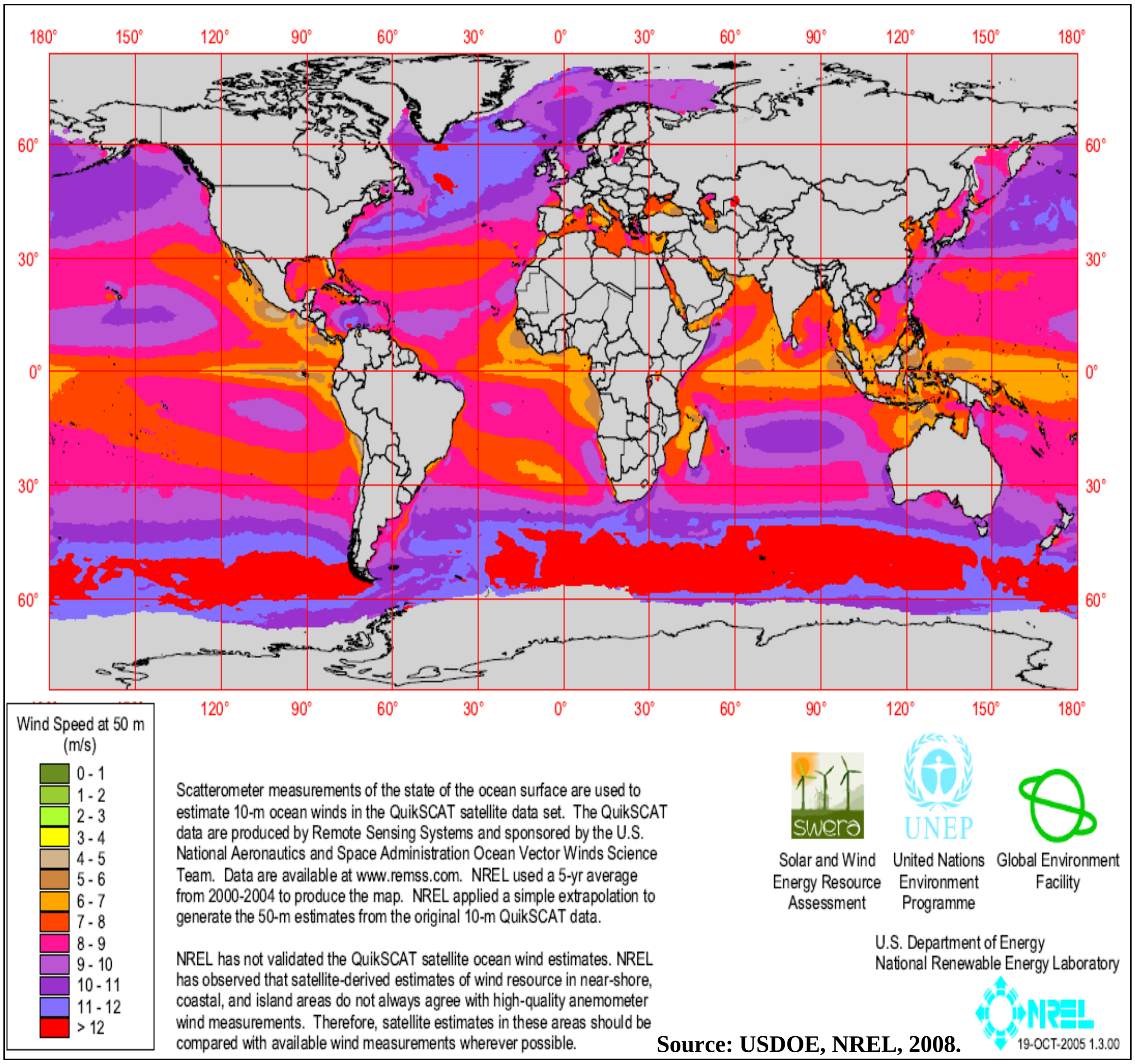
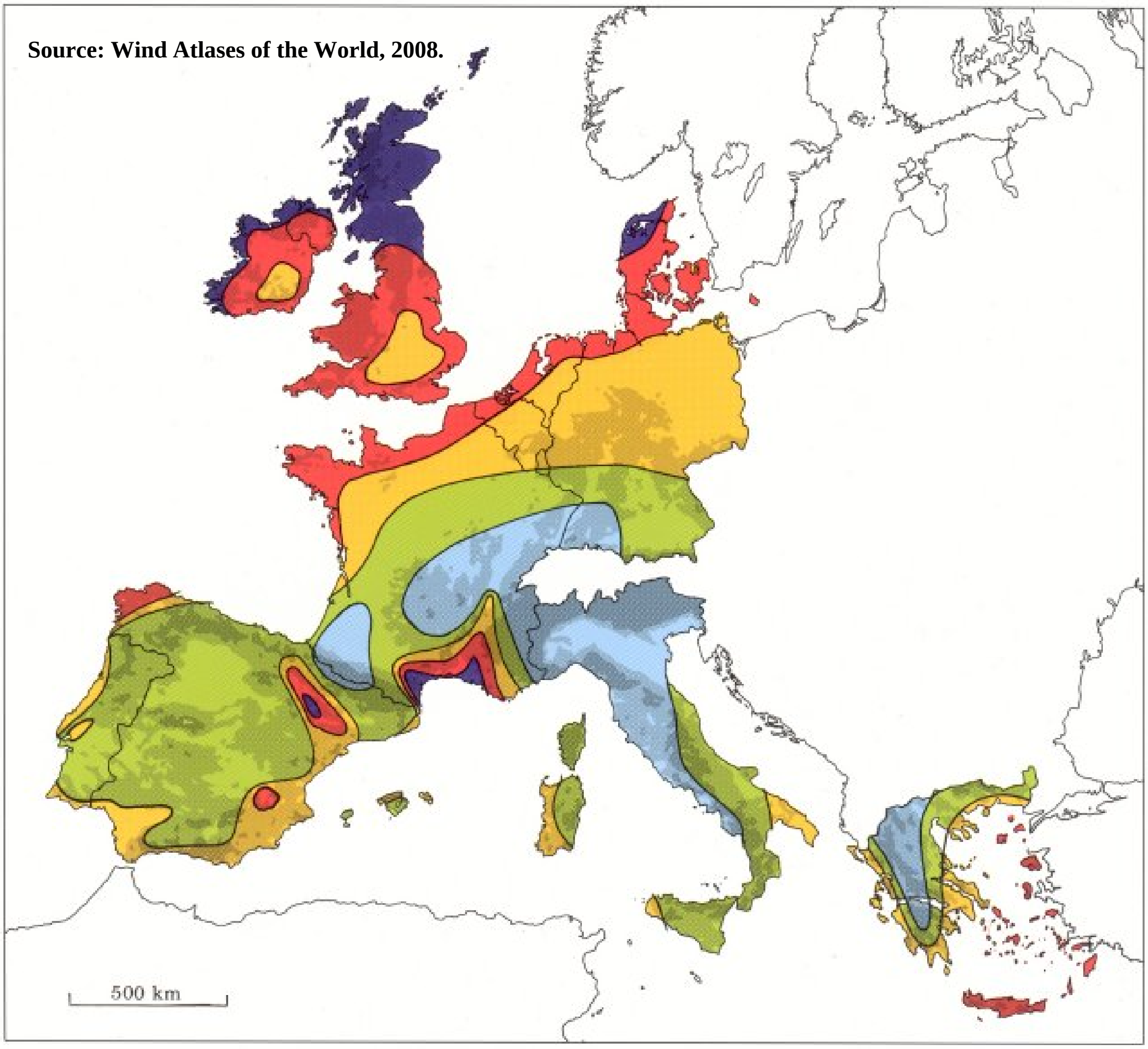


Figure G.21. Annual Average of World Offshore Wind Resources.



Wind resources[1] at 50 metres above ground level for five different topographic conditions

	Sheltered terrain[2]		Open plain[3]		At a sea coast[4]		Open sea[5]		Hills and ridges[6]	
	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}	$m\,s^{-1}$	Wm^{-2}
	> 6.0	> 250	> 7.5	> 500	> 8.5	> 700	> 9.0	> 800	> 11.5	> 1800
	5.0-6.0	150-250	6.5-7.5	300-500	7.0-8.5	400-700	8.0-9.0	600-800	10.0-11.5	1200-1800
	4.5-5.0	100-150	5.5-6.5	200-300	6.0-7.0	250-400	7.0-8.0	400-600	8.5-10.0	700-1200
	3.5-4.5	50-100	4.5-5.5	100-200	5.0-6.0	150-250	5.5-7.0	200-400	7.0- 8.5	400- 700
	< 3.5	< 50	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 7.0	< 400

Figure G.22. Wind Speeds in Europe.

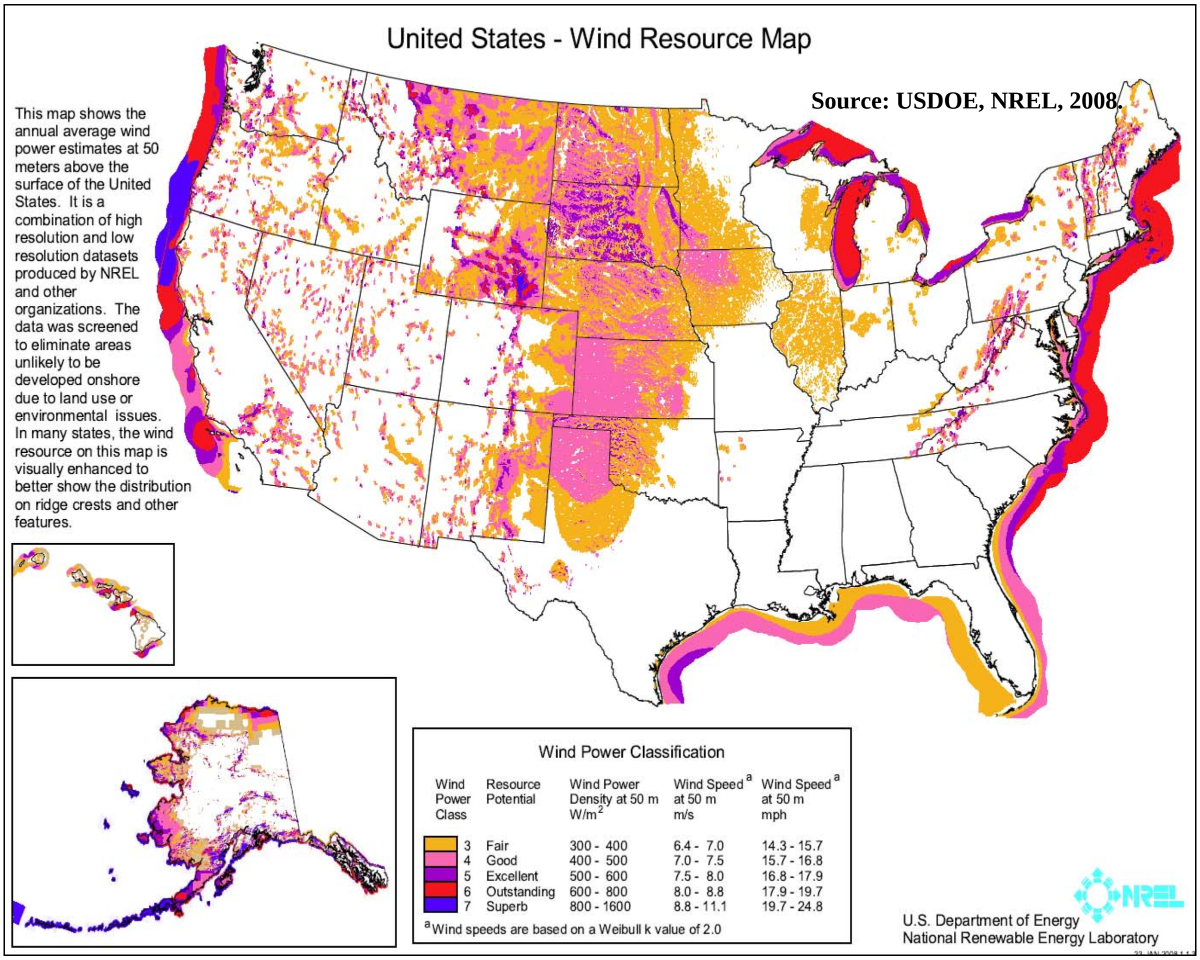


Figure G.23. Wind Speeds in the U.S.

Source: SEDAC, 2008.

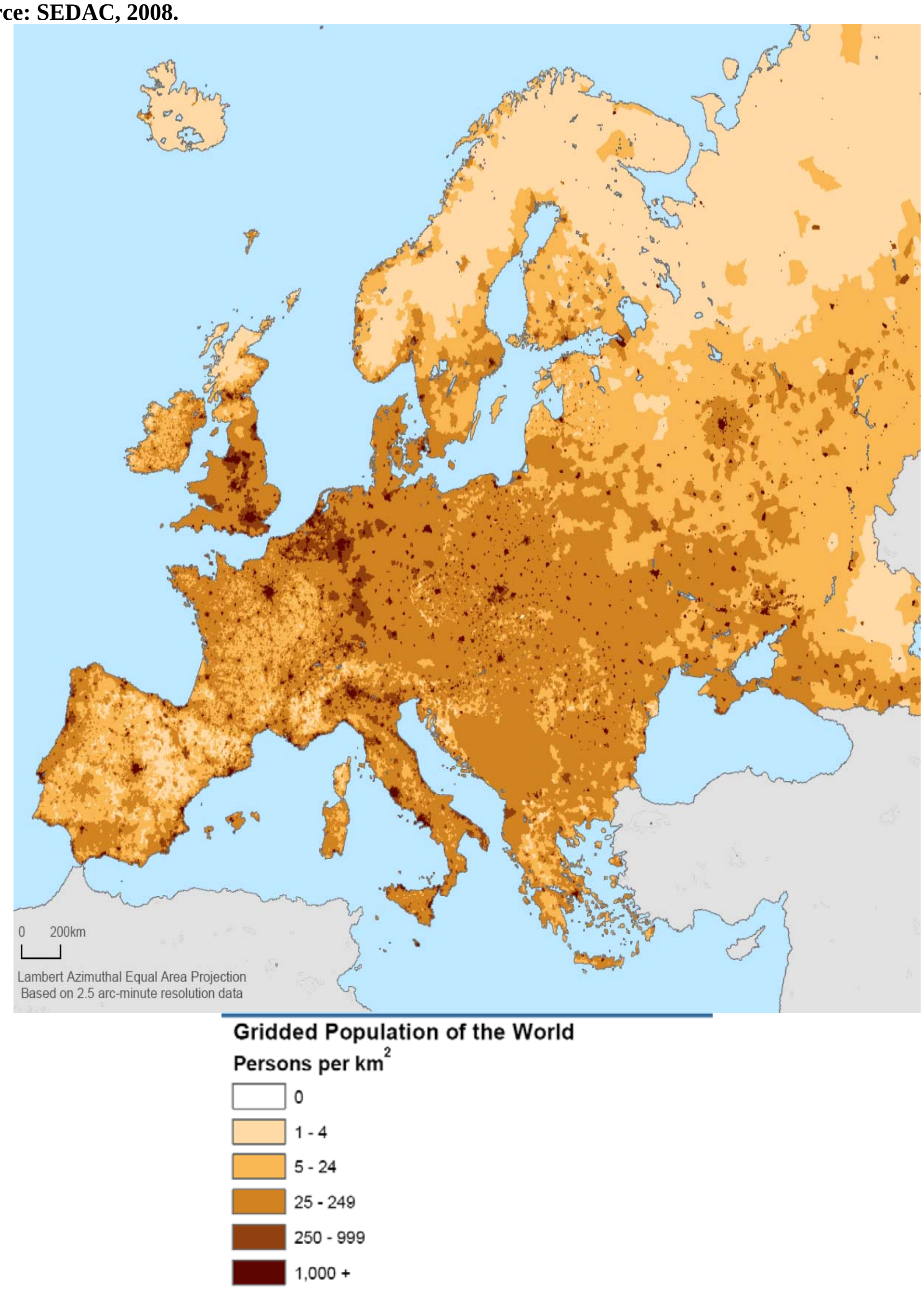


Figure G.24. Population Density of Europe.

Source: SEDAC, 2008.

Figure G.25. Population Density of the U.S.

APPENDIX H.

CHAPTER 8 TABLES AND FIGURES

Table H.1.

Summary of Arguments for and Against Offshore Wind and Comparison to Onshore Wind

Arguments Against Offshore Wind	Applies to Onshore Wind Power	Validity
Ruins special/historic seascape	Y	Aesthetics subjective, but wind turbines are visual disamenity to most. No effect on property values.
Kills birds	Y	Expected death rate 1 to 10 birds per MW. Difficult to compare effects of wind and fossil fuels on bird populations on a per MWh basis.
Harms fisheries	N	Likely to be significant impacts on local fisheries during construction, especially if monopiles are used. During operation fishing success may increase.
Harms marine mammals	N	Likely to have impacts on marine mammals during construction, especially if monopiles are used, potentially including mortality. During operation impacts will be negligible.
Requires subsidies	Y	Offshore wind power not economically competitive with onshore wind or fossil fueled power.
Conflicts w/ shipping & navigation	N	Site dependent. USACE must permit projects and decide if they conflict with navigation.
Hurts tourism	N	Offshore wind projects have caused net increases in tourism.
Arguments For Offshore Wind Power		
Mitigates climate change	Y	Wind power produces very little greenhouse gas emissions over its life cycle.
Decreases water use	Y	Each MW of wind capacity can offset 0.7 to 2.1 million gallons of water consumed per year
Improves air quality	Y	Cape wind estimated to prevent 11 mortalities per year (Kempton et al., 2005), but depends on fuel mix of power actually displaced.
Reduces foreign fuel dependence	Y	Roughly 50% of U.S. electricity comes from coal; U.S. exports more coal than it imports. Roughly 20% of electricity from natural gas. Roughly 20% of this natural gas is imported, almost entirely from Canada.
Creates jobs	Y	The Cape Wind project will create about 50 permanent jobs, plus 100 indirect jobs. Construction will create several hundred additional jobs.
Creates electrical price stability	Y	Wind power provides price stability since cost of producing energy can be forecast, but even most ambitious forecasts only imagine 20% of U.S. electricity supply to come from wind in 2030.
Close to population centers	N	Offshore sources are closer to population centers than onshore wind sources, but it is probably cheaper to build new transmission systems from high-wind onshore sites.
Higher winds offshore	N	Winds are more powerful offshore, but COE of offshore wind is higher than COE of onshore wind, suggesting that higher wind speeds do not make up for higher capital costs.
Reduced user conflicts	N	Site and plan specific; seems to be occurring in Texas, not in Cape Cod.

Source: Firestone and Kempton, 2007; Firestone et al., 2007; USDOI, MMS, 2008a.

Table H.2.

Capital Costs and Cost of Energy of Offshore Wind Farms

Wind Farm or Type of Estimate	Year of Prediction/Estimate	Cost of Energy ($/MWh)	Capital Costs ($/kW)	Source
Generating Costs of Coal Fired Electricity	2003	49		Sims et al., 2003
National Average Wholesale Price of Power (primarily coal, gas and nuclear)	2008	58		Wiser and Bolinger, 2008
Generic Estimate Based on Empirical Data (onshore)	2008	40	1,710	Wiser and Bolinger, 2008
Generic Estimate Based on Small Set of Empirical Data	2005	40-95	1,600-2,600	IEA, 2005b
Theoretical w/ 3MW Turbine	2006	95	2,100	Fingresh et al., 2006
Theoretical 500 MW Farm, 5 MW Turbines, 15 miles from Coast	2004	54	1,200	Musial and Butterfield, 2004
LIOWP (cancelled)	2007	291	5,231	PACE, 2007
Generic Estimate for Future Wind Farm	2007		4,000	PACE, 2007
General Based on Empirical Data	2007	100	3,200	DTI, 2004
Cape Wind	2007	122		Mense, 2007
Estimates from Proposed Wind Farms	2001	48-70		Barthelmie and Pryor, 2001
Generic Estimate Based on All Available Empirical Data	2008		3,354	Data in Table 3
Middelgrunden	2005	70		Larsen et al., 2005
Theoretical Generic Estimate	2006		3,500	Lemming et al., 2007
Empirical Data	2003		2,200-2,600	Morgan et al., 2003

Table H.3.

Costs of Offshore Wind Farms in Europe

Wind Farm	Nation	Year Constructed	Capacity (MW)	Total Cost[a] (million)	Depth (m)	Turbine size (MW)	Number of Turbines	Distance to Shore (km)	Sources[b]
Vindeby	Denmark	1991	5	11.2	3.5	0.45	11	1.5	1, 3, 7, 4
Lely	Netherlands	1994	2	4.8	7.5	0.5	4	0.8	1, 3, 6, 1, 7, 10, 4
Tuno Knob	Denmark	1995	5	11.2	4	0.5	10	3	1, 3, 5, 10, 4
Dronten	Netherlands	1996	11	28.6	1.5	0.6	19	0.03	1, 3, 7, 10
Bockstigen	Sweden	1997	3	4.8	6	0.55	5		1, 3, 4
Blyth	UK	2000	4	7	8.5	2	2	1	1, 3, 4
Middlegrunden	Denmark	2001	40	53	6	2	20	2	1, 3, 4, 13
Utgrunden	Sweden	2001	10	14	8.6	1.425	7		1, 3, 4, 10
Yttre Stengrund	Sweden	2001	10	18	8	2	5		1, 3, 4, 5
Horns Rev	Denmark	2002	160	500	10	2	80	14	1, 3, 6, 7, 10
Nysted	Denmark	2003	158	373	7.75	2.3	72	10	1, 10
Samso	Denmark	2003	23	52	20	2.3	10	3.5	1, 3, 5
North Hoyle	UK	2003	60	148	12	2	30	7	1, 10
Ronland	Denmark	2003	17.2	26	1	2.3	8		1, 3
Scroby Sands	UK	2004	60	155	16.5	2	30	2.5	1, 12
Arklow	Ireland	2004	25	70	3.5	3.6	7	10	1, 3
Kentish Flats	UK	2005	90	217	5	3	30	10	1, 10
Barrow	UK	2006	90	190	17.5	3	30	7.5	1, 5, 6, 7
Egmond aan Zee	Netherlands	2006	108	334	18	3	36	10	1, 12
Burbo Bank	UK	2007	90	185	5	3.6	25	6.5	1, 10
Beatrice	UK	2007	10	70	45	5	2	22	10
Lillgrund	Sweden	2007	110	300	7	2.3	48	10	6
Q7	Netherlands	2007	120	590	21.5	2	60	23	14
Lynn/Inner Downsing	UK	2008	90	600	9.5	3.6	54	5	5
Robin Rigg	UK	2008	180	765	5	3	60	9	5
Throton bank	Belgium	2008	300	1,250	14	5	60	27	1

Footnote: (a) Adjusted for inflation using the Bureau of Labor Statistics calculator and exchange rates at the time of construction.

(b) 1= Lemming et al., 2007; 3= Beurskens and Noord, 2003; 4= Barthelmie and Pryor, 2001; 5= Power Technology, 2008; 6= Vattenfall, 2008; 7=A2sea, 2008; 8= IEA, 2005a; 9= Airtricity, 2008; 10=OffshoreWindEnergy.org, 2007; 11= Enova, 2008; 12=Gerdes et al., 2007. 13= Larsen et al., 2005; 14=Econcern, 2008.

Table H.4.

Parameter Estimates from the Three Best Models from Multiple Regressions

Total Cost (million \$) = $\beta_0 + \beta_1$*(year) + β_2*(distance to shore (m)) + β_3*(turbine size(MW)) + β_4 *(capacity (MW)) + β_5*(water depth (m))			
Parameter	Model 1	Model 2	Model 3
β_0	-21,029 (0.2281)	18.02 (0.6929)	-19,293 (0.2890)
β_1	10.53 (0.2271)		9.66 (0.2887)
β_2	9.28 (0.015)	9.97 (0.0007)	8.43 (0.0111)
β_3	-56.14 (.0204)	-39.06 (0.0346)	-57.68 (0.0229)
β_4	2.45 (<0.0001)	2.65 (<0.0001)	2.53 (<0.0001)
β_5			1.05 (0.5825)
Adj R^2	0.92 (<0.0001)	0.91 (<0.0001)	0.91 (<0.0001)

Note: P-values reported in parentheses.

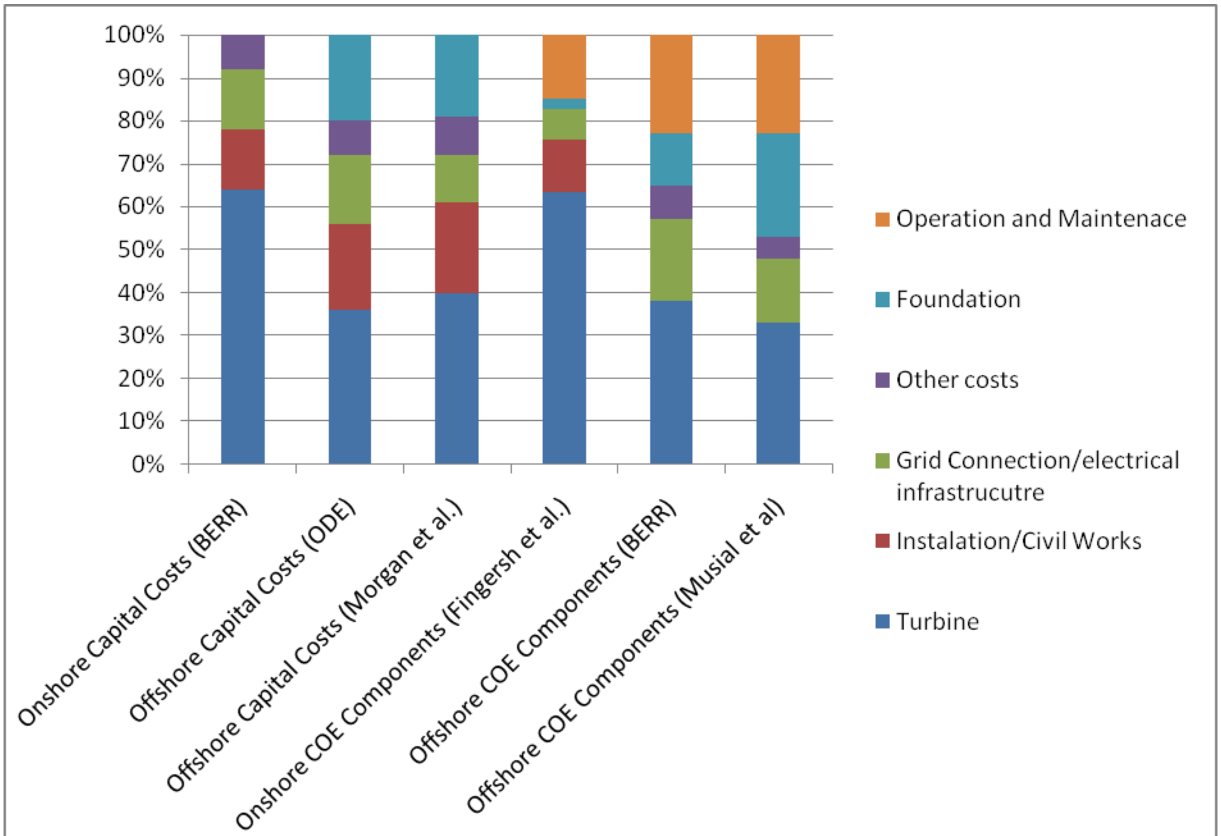
Table H.5.

Environmental Impacts Associated with Cape Wind Development According to the EIS

	Affected Resource	Construction Impacts[a]	Operation Impacts
Oceanography	Currents	No measurable impacts	Minor
	Waves	No measurable impacts	No measurable impacts
	Salinity	No measurable impacts	No measurable impacts
	Temperature	No measurable impacts	No measurable impacts
	Sediment transport	Minor	Minor
	Water depth	Minor	Minor
Birds	Raptors	No measurable impacts	No measurable impacts
	Passerines	Minor	No measurable impacts to Minor
	Coastal species	No measurable impacts to Minor	No measurable impacts to Moderate
	Marine birds	Minor to moderate	Minor to moderate
Invertebrates	Benthic invertebrates	Minor	Minor
	Shellfish	Minor	Minor
	Plankton	No measurable impacts	Minor
Fisheries	Finfish	Minor	No measurable impacts to Minor
	Demersal eggs and larvae	Moderate	No measurable impacts to Moderate
	Fish habitat	No measurable impacts to Minor	No measurable impacts to Minor
Marine Mammals	Marine Mammals	Minor to moderate	No measurable impacts to Moderate
Endangered Species	Sea Turtles	No measurable impacts to Minor	No measurable impacts to Minor
	Cetaceans	No measurable impacts to Minor	No measurable impacts to Minor
	Birds	No measurable impacts to Minor	No measurable impacts to Moderate

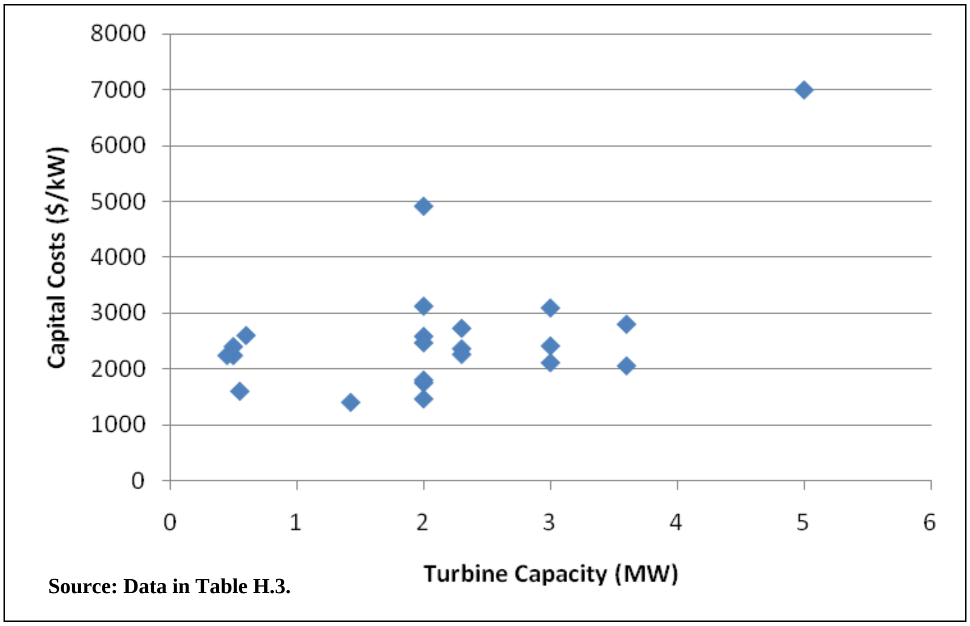
Source: USDOI, MMS, 2008a.

Footnote: (a) Minor impacts are those that can be completely mitigated against or are small enough that the resource can recover completely on its own. Moderate impacts occur if either the impact is immitigable but the resource could recover on its own, or if the impact can be partially mitigated and the resource could then recover on its own. Major impacts occur if the impact is immitigable, the viability of the resource is threatened and the resource would not fully recover.



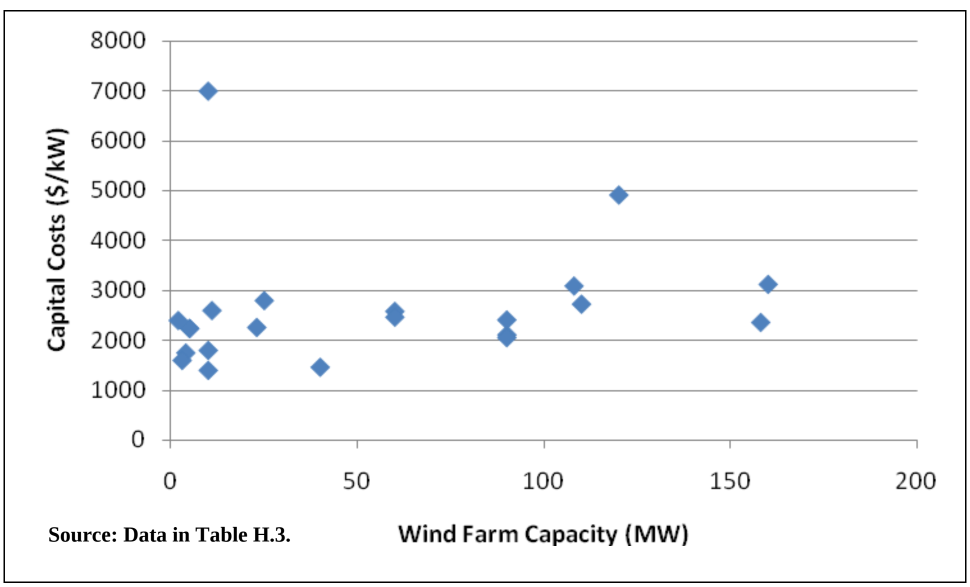
Sources: Dept. for BERR, 2004; ODE, 2007; Morgan et al., 2003; Fingersh et al., 2006; Musial et al., 2006.

Figure H.1. Costs of Onshore and Offshore Wind.



Source: Data in Table H.3.

Figure H.2. Capital Costs Versus Turbine Size.



Source: Data in Table H.3.

Figure H.3. Capital Costs as a Function of Wind Farm Size.

APPENDIX I.

CHAPTER 9 TABLES AND FIGURES

Table I.1.

Major Lease Terms and Components for Selected Offshore Wind Regulatory Authorities

Major Issue	UK	Denmark	BLM (onshore)	Texas	BOEMRE
Lease Terms: Leasing Fees and Royalties, Phased Access	Developers pay application fee of £2,500 and one time lease fee of up to £500,000 depending on size of site. Developers are eligible for capital grants; exempt from climate change levy (4.3 p/kWh), can sell renewable obligation credits (5p/kWh; Toke 2007).	Price of electricity agreed upon in tender. Recent tender price 13.2 c/kWh. No phased access. Lessees have three years from lease to construct wind farm.	Phased access system granting data collection and competitive exclusion rights. Fee for commercial development $2,365 per MW of capacity.	Phased access in which developer has right to terminate lease. $20,000 phase 1 fee and 3.5 to 5.5% royalty during operation.	First 5 years of lease used for assessment. Royalty rates and bonus bids vary competitively.
Term Limit	40 or 50 years with a renegotiation after 20 or 25 years	25 years	None	30 years	30 years
Competitive Process	Government selects sites with input from developers. Process has preceded in rounds, not unlike BOEMRE five year plans.	Set lease areas and hold competitive bidding.	First come-first served basis. Competing applicants encouraged to form cooperative agreement.	Set lease areas and hold competitive bidding.	Competitive auction for sites with competitive interest. Use highest bonus bid or royalty rate.
Approval Criteria	Feasibility of development plan.	Lowest feed in price per kWh.		Highest bidder.	Highest bidder.
Environmental Analyses	BERR completed SEA for areas to be leased. Developers complete EIS for sites.	Developer conducts site specific EIS after competition. Exceptions may be made by DEA.	Use CX's for data monitoring and EA for commercial development. Occasional use of EIS.	Has to comply with COE NEPA requirements. Has to conduct avian and bat studies if EIS is not required.	Multiple opportunities for environmental analysis. Site specific EIS usually required.
Operational Issues: Environmental and Compliance Monitoring, Safety	Developers conduct monitoring and submit reports.	Each developer submits operational plans and conducts their own environmental monitoring.	Little discussion of operational issues.	Monitoring conducted by lessee with reports issued to state.	Developers conduct monitoring according to approved plan and issue reports. BOEMRE conducts inspections.
Decommissioning	Surety bonds or other financial instrument required. Allow for repowering or reuse of facilities.	Developer must submit approved financial guarantee to DEA.	Bonds are required; amount of bond determined on site specific basis.	Surety bonds, cash deposit or letter of credit required.	Surety bond or other guarantee required. Detailed decommissioning plan does not need to be submitted until 2 years before end of lease.

Sources: Toke, 2007; DEA, 2007 and 2008; USDOI, BLM, 2006; Texas General Land Office, 2007a; USDOI, MMS, 2009.

Table I.2.

Texas Royalty System

	Preproduction	Years 1-8	Years 9-16	Years 17-30
Minimum Royalty	0	3.5%	4.5%	5.5%
Minimum Annual Royalty per MW		\$4,100	\$5,500	\$7,000
Other fees	\$20,000 per year (approximately \$1 per acre)			

Source: Texas General Land Office, 2007a.

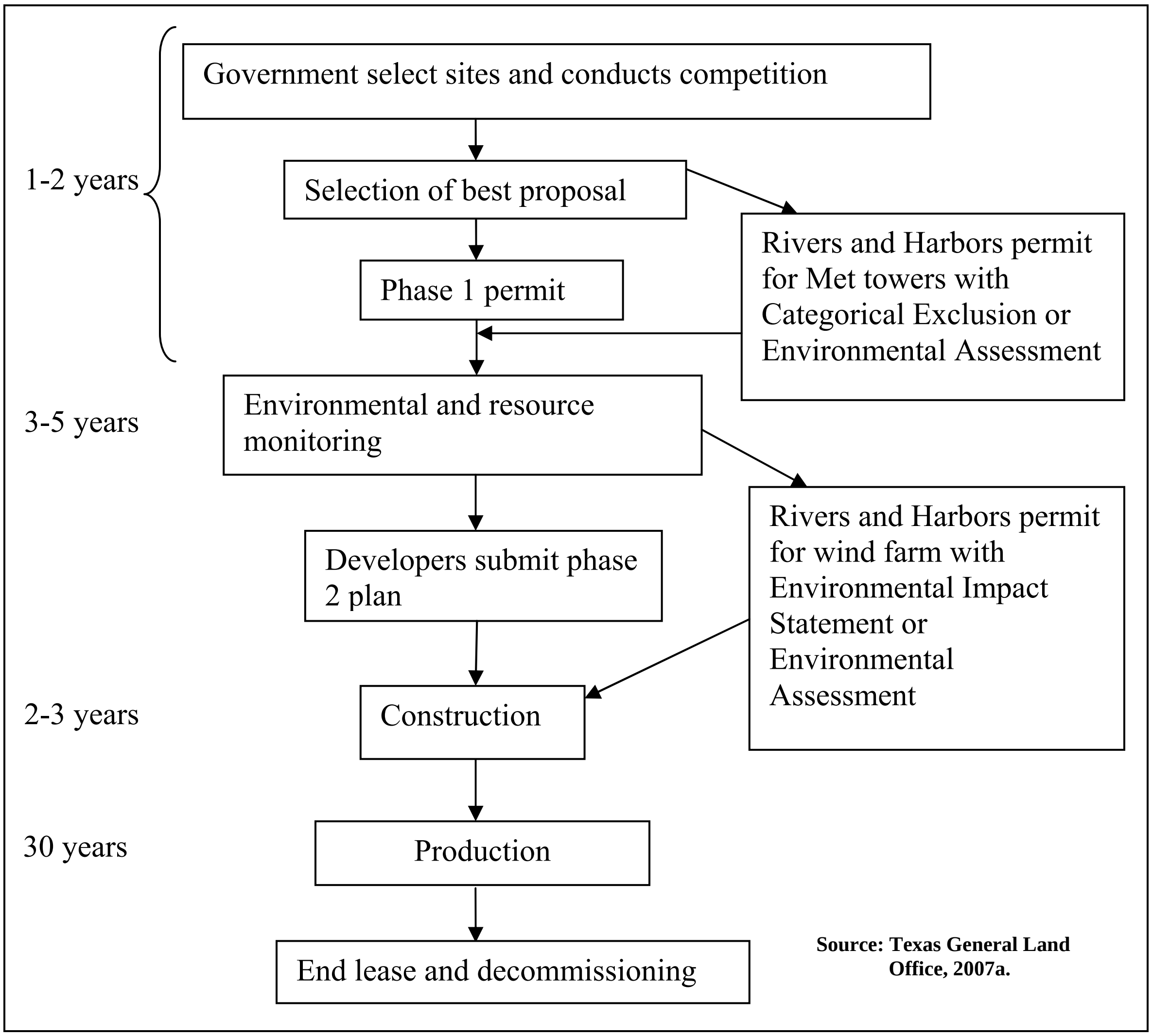
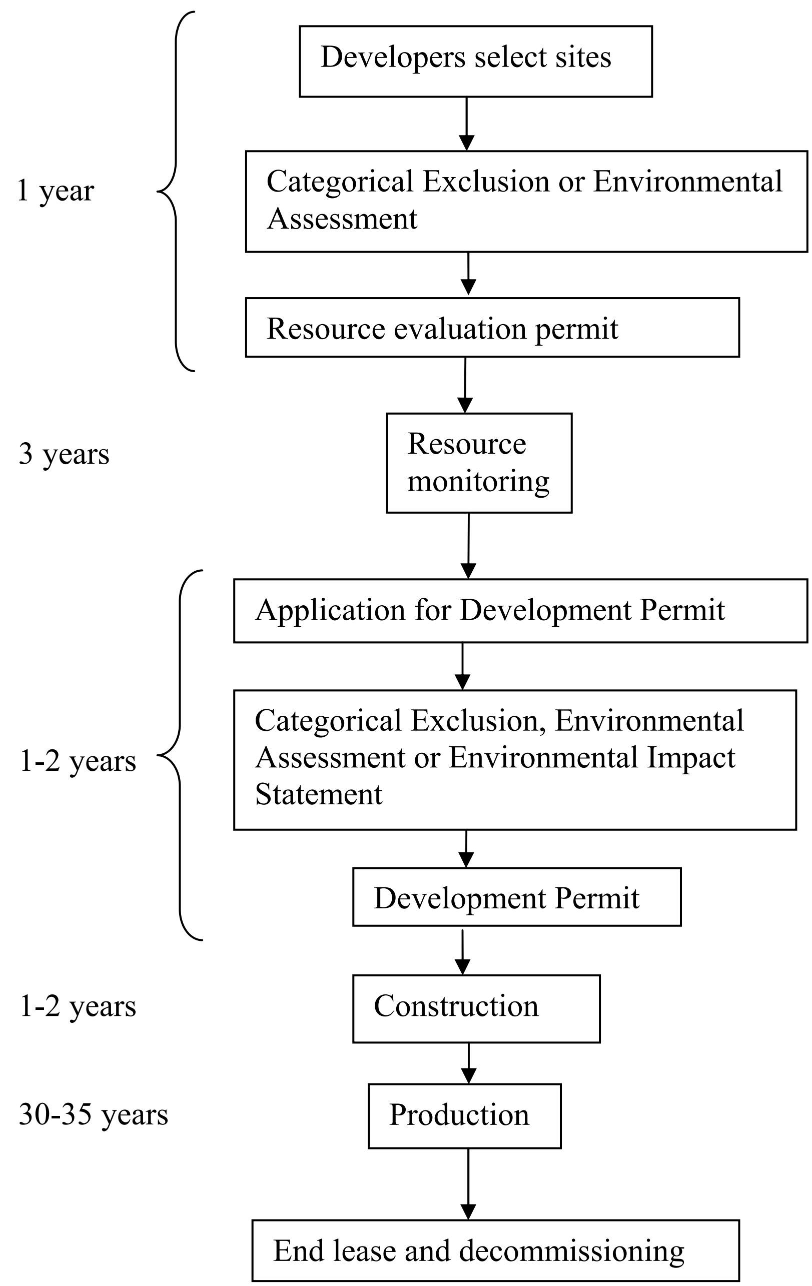


Figure I.1. Flow Chart of Texas Regulatory Process.



Source: USDOI, BLM, 2006.

Figure I.2. Flow Chart of BLM Regulatory Process.