

**ANALYZING COSTS AND BENEFITS OF
REROUTING VESSEL TRAFFIC TO OPEN AREAS
FOR OFFSHORE WIND DEVELOPMENT
IN THE MID-ATLANTIC UNITED STATES**

by

Kateryna Samoteskul

A thesis submitted to the Faculty of the University of Delaware in partial fulfillment of the requirements for the degree of Master of Science in Marine Studies

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TABLE OF CONTENTS

LIST OF TABLES	x
LIST OF FIGURES	xii
ABSTRACT	xiii

Chapter

1	INTRODUCTION	1
1.1	Background.....	1
1.2	Overlapping Needs of Commercial Shipping and Offshore Wind.....	2
1.3	Objective and Scope	4
1.4	Organization of the Thesis.....	7
2	LITERATURE REVIEW	8
2.1	Introduction	8
2.2	Research on Vessel Rerouting and Its Economic Impacts	8
2.2.1	Vessel Rerouting Using Spatial Data Analysis Tools	8
2.2.2	Economic Impact of Vessel Traffic Rerouting.....	9
2.2.3	Studies on Components of Vessel Added Costs.....	12
2.2.4	Other Transportation Modes and Impacts of Rerouting.....	13
2.2.5	Impacts on Collision and Allision Risk due to Rerouting.....	14
2.2.5.1	Selected Models and Data Sources.....	15
2.3	Research on Offshore Wind Power Costs	15
2.3.1	Wind Project Components and Costs	15
2.3.2	Distance from Shore and Transmission Cable Options.....	19
2.3.2.1	Transmission Cables Cost	20
2.3.2.2	Transmission System Losses.....	21
2.3.3	Wind Transportation Cost	23
2.3.4	Operating and Maintenance Costs.....	25

2.3.5	Capital Cost Financing for Wind Projects.....	26
2.3.6	Other Studies on Cost of Offshore Wind Energy	28
2.4	Selected Models.....	29
2.4.1	Social Cost of Air Pollutants	30
2.4.1.1	Health and Environmental Impacts of Air Pollutants... 30	
2.4.1.2	Quantifying Emissions from Ship Traffic	31
2.4.1.3	Monetizing Emissions to Determine Social Costs	33
2.4.1.4	Emissions from Transportation of Offshore Wind Components and O&M.....	34
2.4.1.5	Selected Models.....	35
2.4.1.6	Conclusions	35
3	THEORETICAL FRAMEWORK AND METHODOLOGY	38
3.1	Spatial Data Analysis	38
3.1.1	The Study Area.....	38
3.1.2	Detailed Methods.....	39
3.1.2.1	Datasets Used	39
3.1.2.2	Affected Vessels.....	40
3.1.2.3	Modeling Vessel Density	41
3.1.2.3.1	Selecting Vessel Trips for Analysis	41
3.1.2.3.2	Calculating Vessel Density for Each Grid Cell	43
3.1.2.4	Determining the Total Population of Affected Vessel Trips.....	45
3.1.2.5	Selecting a Sample of Affected Vessel Trips for Economic Analysis.....	47
3.1.2.6	Measuring the Extent of Rerouting	49
3.1.3	GIS Analysis of Bathymetry for Offshore Wind Energy Areas..	53
3.1.3.1	Determining Hypothetical Locations of Status Quo and Alternative Wind Energy Areas (WEAs)	54
3.1.3.1.1	Alternative WEAs (ALT-WEAs).....	54
3.1.3.1.2	Status Quo WEAs (SQ-WEAs).....	55
3.1.3.2	Determining Bathymetry within the WEAs	59

3.1.4	Cost-Benefit Analysis (CBA).....	60
3.1.4.1	CBA as a Framework	60
3.1.4.1.1	Examples of Cost-Benefit Analysis Studies	61
3.1.4.2	Valuing Direct and Indirect Costs and Benefits	62
3.1.4.3	Costs and Benefits Components that Are Not Monetized	63
3.1.5	Modeling Direct Costs to Commercial Shippers before and after Rerouting.....	63
3.1.5.1	Modeling Fuel Costs.....	64
3.1.5.1.1	Assumptions Regarding Fuel Used	67
3.1.5.2	Modeling Operating Costs.....	69
3.1.5.3	Modeling Capital Costs	70
3.1.5.4	Calculating the Total Added Vessel Cost.....	72
3.1.5.5	Extrapolating the Cost to All Affected Vessels.....	72
3.1.6	Modeling Cost of Offshore Wind Projects before and after Rerouting	73
3.1.6.1	Estimating the Number of Turbines in Each Alternative Wind Energy Area	74
3.1.6.2	Estimating Wind Turbine Spacing and Nameplate Capacity	75
3.1.6.3	Modeling Transmission Cable Losses for HVAC and HVDC Cable Options.....	76
3.1.6.4	Estimating the Number of Turbines in the Status Quo WEAs	78
3.1.6.5	Modeling Foundation Weight and Cost	79
3.1.6.5.1	Jackets.....	80
3.1.6.5.2	Floating Foundation (Tension Leg Platform - TLP)	80
3.1.6.6	Modeling Transmission Cable Cost	81
3.1.6.6.1	High-Voltage Alternating Current (HVAC)	81

	3.1.6.6.2	High-Voltage Direct Current (HVDC).....	82
	3.1.6.7	Modeling Transmission Cable Installation.....	83
	3.1.6.8	Modeling Transportation Cost.....	83
	3.1.6.8.1	Modeling the Cost of Transporting Turbines and Jacket Foundations	83
	3.1.6.8.2	Modeling the Cost of Transporting Turbines Placed on Floating Foundations	85
	3.1.6.9	Modeling the Cost of Operation and Maintenance.....	85
	3.1.6.10	Modeling Capital Cost Payments from Offshore Wind Projects	87
	3.1.7	Modeling Changes in Vessel Emissions and their Social Costs	87
	3.1.7.1	Modeling the Social Cost of Emissions from Commercial Ship Traffic.....	88
	3.1.7.2	Modeling the Social Cost of Emissions from Transporting Turbine Components via Tugs.....	89
	3.1.7.3	Emissions during O&M for Wind Projects	91
	3.1.8	Estimating Impacts over the Duration of the Proposed Policy....	91
	3.1.8.1	Time Structure of Costs and Benefits.....	91
	3.1.8.2	Discounting and Calculating Net Present Values.....	92
	3.1.8.3	Robustness of the Model and Sensitivity Analysis	94
4	RESULTS.....		96
	4.1	Costs	96
	4.1.1	Annual Added Costs.....	97
	4.1.2	Total Added Costs	100
	4.2	Benefits.....	100
	4.2.1.1	New Jersey WEA	100
	4.2.1.2	Delaware WEA.....	103
	4.2.1.3	Maryland and Virginia WEAs.....	105
	4.2.2	Added Benefits (Cost Savings) for All WEAs before Discounting.....	108

4.3	Present Value of Net Benefits	110
4.4	Sensitivity Analysis	110
5	DISCUSSION AND CONCLUSIONS	112
5.1	Overview	112
5.2	Wind Project Components that Are Not Monetized.....	112
5.2.1	Putting the Findings into Context.....	113
5.2.1.1	The Added Cost per Metric Ton of Goods Transported.....	113
5.2.1.2	Additional Wind Capacity that Could Be Built with the Benefits.....	113
5.2.1.3	Displaced CO ₂ if Additional Wind Capacity is Built	114
5.2.1.4	Reduction in the Cost of Power if the Near-Shore Wind Areas Are Developed.....	114
5.2.2	Uncertainties, Model Improvements and Future Research	115
5.2.2.1	Vessel Costs.....	115
5.2.2.2	Wind Project Costs	116
5.2.2.3	Indirect Costs of Air Emissions.....	117
5.2.2.4	Future Areas of Research	117
5.2.3	Policy Recommendations and Conclusions.....	118
	REFERENCES	123

Appendix

A	PUTTING FINDINGS IN CONTEXT	134
6.1	The Added Cost per Metric Ton of Goods Transported.....	134
6.2	Additional Wind Capacity that Could Be Built with the Benefits	134
6.3	Displaced CO ₂ if Additional Wind Capacity Is Built.....	135
6.4	Reduction in the Cost of Power if the Near-Shore Wind Areas Are Developed.....	136

LIST OF TABLES

Table 2.1: Scale factor for cost increases as a function of water depth and distance to shore.....	17
Table 2.2: Losses in MW/km based on three cable options. The losses are optimized for a 320 kV 1,000 MW cable.....	23
Table 2.3: Cost of O&M for offshore wind projects at different distances from shore.....	26
Table 2.4: Emission factors in 2020, in g/kWh.....	32
Table 2.5: Emission factors (kg/metric ton fuel equivalent) in 2020 (except for CO ₂).....	33
Table 3.1: Vessel types used for estimating ship traffic densities (after the original dataset is simplified, clipped and projected).....	43
Table 3.2: Breakdown of vessel trips by route from the sample.....	48
Table 3.3: Average vessel route lengths before and after rerouting.....	50
Table 3.4: Primary foundation technology and percentage of area for SQ and ALT-WEAs.....	60
Table 3.5: Average vessel route lengths before and after rerouting (in km and nautical miles (nm)).....	65
Table 3.6: Average operating speed and design speed by ship type.....	66
Table 3.7: Average main engine power by vessel type (based on the sample).....	67
Table 3.8: Average price for new vessels.....	71
Table 3.9: Losses of MW/km based on two cable options; the losses are optimized for a 320 kV 1,000 MW cable.....	76
Table 3.10: Approximated Capacity Factors (CF _{gross}) for SQ and ALT-WEAs (for a 5 MW turbine).....	78

Table 3.11: Floating TLP foundation component fabrication cost and weight to support a 5 MW turbine	81
Table 3.12: Day rate (operating cost) and fuel cost and other parameters for a 6,000 horsepower tug.....	84
Table 3.13: O&M costs at different distances from shore.....	86
Table 3.14: Emission factors (kg/metric ton fuel equivalent) in 2020 (except for CO ₂). Emission factors for CO ₂ are in kg of CO ₂ /kg of fuel. These are adjusted for the calculations of emissions added during rerouting.....	88
Table 3.15: Social cost of air pollutants (adjusted to 2012\$).....	89
Table 3.16: Tug characteristics. The fuel amount in gallons is converted to metric ton using the density of 0.981 grams/ml.....	90
Table 4.1: Summary of added annual cost during rerouting based on the number of trips taken in 2009, in 2012\$ before discounting	98
Table 4.2: Added annual cost of vessel rerouting during the 29 years of project operation (escalated at 2.2% annually starting in 2012).....	99
Table 4.3: New Jersey WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$.....	102
Table 4.4: Delaware WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$.....	105
Table 4.5: Maryland and Virginia WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$	108
Table 4.6: The estimated direct and indirect benefits for WEAs. All values are in billion 2012\$ before discounting	108
Table 4.7: Summary of annual costs and benefits and the present value calculation.....	109
Table 4.8: Present value costs, benefits and net benefits (3.5% social discount rate)	110

LIST OF FIGURES

Figure 1.1: Relative density of vessel traffic in the Mid-Atlantic and WEAs	7
Figure 3.1: Finalizing the vessel traffic dataset for density analysis.....	42
Figure 3.2: Relative density of vessel traffic in the Mid-Atlantic and existing WEAs	44
Figure 3.3: Determining the total population of vessels affected by the rerouting	45
Figure 3.4: Ship traffic density and the vessel trips affected by the proposed rerouting scenario	47
Figure 3.5. Selecting the sample of affected vessel trips for economic analysis	48
Figure 3.6: Vessel traffic density and the routes between the Mid-Atlantic ports proposed to be modified	51
Figure 3.7: Vessel traffic density and the redirected vessel routes between the Mid-Atlantic ports (the alternative scenario)	52
Figure 3.8: Status quo and alternative vessel routes.....	53
Figure 3.9: Affected current habitual vessel traffic pattern and Alternative Wind Energy Areas (ALT-WEAs) that could be open for development if the traffic are rerouted	55
Figure 3.10: Affected current habitual traffic pattern, ALT-WEAs that could be opened to development and SQ-WEAs that would have to be developed if vessels are not rerouted.....	57
Figure 3.11: Status quo and alternative vessel routes and WEAs	58
Figure 4.1: Foundation types for SQ and ALT-WEA off New Jersey	101
Figure 4.2: Foundation types for SQ and ALT-WEA off Delaware	104
Figure 4.3: Foundation types for SQ and ALT-WEA off Maryland and Virginia...	106

ABSTRACT

The recent emphasis on development of offshore wind energy projects has powered the movement to evaluate distribution of current ocean activities. As wind energy development becomes more prevalent, existing users of the oceans, such as commercial shippers, will be compelled to share their historically open-access waters with these projects. Here, we demonstrate the utility of using cost-benefit analysis (CBA) framework to reduce potential spatial conflicts and assess tradeoffs between offshore wind development and commercial shipping. Specifically, we evaluate whether rerouting commercial vessel traffic farther from shore to open areas for wind development would produce net societal benefits. We focus on less than 1,500 transits by deep-draft vessels between the ports in the US Mid-Atlantic. We propose to reroute these ships by an average of 18.5 km (10 nautical miles) per trip. We estimate that over 29 years of the study, the added private and external vessel costs amount to approximately \$0.2 billion (in 2012\$). The net benefits of the proposed policy are approximately \$14 billion (in 2012\$). Considering the large societal benefits, modifying areas where vessels transit needs to be included in the portfolio of policies used to support the launch and growth of the offshore wind industry in the US.

Chapter 1

INTRODUCTION

1.1 Background

The US Mid-Atlantic ocean waters are heavily utilized areas that accommodate a diverse range of human activities. Commercial shipping, commercial and recreational fishing, beach nourishment areas, recreational boating, and cable crossings co-exist in the ocean (MARCO, 2010). Some of the established users, such as commercial shipping, utilize vast ocean areas. Thus, major traffic routes intersect the region, while the Mid-Atlantic seaports are entryways to more than 60% of the US market. For the nation as a whole, commercial shipping moves approximately 95% of foreign trade (US Department of Transportation (US DOT), 2011). In the next three decades, trade is projected to grow twice as fast as the US economy as a whole, with exports and imports comprising approximately 55% of GDP by 2038 (ibid). The value of trade is expected to reach \$27 trillion dollars (in real 2000\$) in 2038 (IHS, 2009).

Emerging uses, such as offshore wind energy development, are increasingly acting as catalysts for spatial reallocation of ocean resources. With the recent emphasis on energy security, domestic growth and reducing air pollution, historic ocean users, such as commercial shipping, will be compelled to share their historically unobstructed Mid-Atlantic waters with offshore wind projects. In 2011, the US Department of Energy (DOE) has set a goal to develop 54 GW of offshore wind capacity by 2030 (US DOE, 2011). To meet this target, large-scale deployment of offshore wind energy will need to take place in the next several decades. These wind

projects will harness the immense wind resource potential of the US Atlantic Coast, which contains approximately 1,000 GW of energy (US DOE, 2011). If fully developed, it is equivalent to the country's current generation capacity (ibid). The wind resource is also close to large, densely populated areas where electric rates are high, demand for power is growing steadily, and land-based wind development is constrained (Musial and Ram, 2010).

Even though as of 2012, no offshore wind facilities have been built in the US, but several projects are in the planning and permitting stages. Four projects are in the pipeline off the coast of New Jersey and Delaware (Musial and Ram, 2010). These projects are primarily located within Wind Energy Areas (WEAs) designated by the Bureau of Ocean Energy Management (BOEM) for future offshore wind development. Such lease blocks have been identified off the North Eastern and the Mid-Atlantic US.

1.2 Overlapping Needs of Commercial Shipping and Offshore Wind

As commercial shipping and offshore wind energy projects are mutually exclusive uses, the two uses will compete for ocean space. Careful planning will be required to ensure that offshore wind projects will be built not to impede the activities of the maritime industry and to minimize risk of collisions and allisions.

Already, the tensions created by poor siting of wind energy areas halted development. Thus, some WEAs were located either in or at the seaward terminus of existing TSSs (USCG, 2011). Other WEAs were placed in the traditional vessel routes used on Atlantic coastwise transits and for foreign vessel movements. This created unnecessary controversy and confusion and delayed development. In the end, the Maryland wind lease blocks were reduced from 536 km² to 243 km² (BOEM, 2011). Massachusetts WEA was also amended due to concerns over navigational safety.

Recognizing the need to assess the effects of siting of offshore renewable energy installations on vessel traffic, the US Coast Guard is conducting a *Port Access Route Study: The Atlantic Coast from Maine to Florida (PARS)* (USCG–2011–0351). The goal of PARS is “to enhance navigational safety by examining existing shipping routes and waterway uses, and, to the extent practicable, reconciling the paramount right of navigation within designated port access routes with other reasonable waterway uses such as the leasing of outer continental shelf blocks for the construction and operation of offshore renewable energy facilities” (USCG, 2011, p 27288). The interim report emphasized the need for further research in order to predict changes in vessel traffic patterns and to determine the resultant change in navigational safety risk based on different siting scenarios for offshore renewable energy installations (USCG, 2012).

Ultimately, the challenge lies in determining the balance between complying with the Ports and Waterways Safety Act (PWSA) (33 U.S.C. 1223(c)), which through designation of fairways and Traffic Separation Schemes (TSSs)¹ recognizes “the paramount right of navigation over all other uses in the designated areas²” (USCG, 2011, p 27289) and reaching the goal to build 54 GW of offshore wind by 2030, with potential for more development in the future.

¹ Traffic Separation Scheme (TSSs) – “a routing measure aimed at the separation of opposing streams of traffic by appropriate means and by the establishment of traffic lanes” (U.S.C.G., 2011). TSSs are often established near approaches to ports.

² The designated areas here implies areas the Secretary assigns as “necessary fairways and traffic separation schemes for vessels operating in the territorial sea of the United States and in high seas approaches, outside the territorial sea, to such ports or places” (PWSA, 33 U.S.C. 1223(c)).

Developing tools to measure the costs and benefits of the potential modifications to vessel routing measures is required to make science-based decisions about allocation and management of ocean spatial resources.

1.3 Objective and Scope

The aim of this study is to determine whether there would be net societal benefits from directing vessels traveling between the Mid-Atlantic ports to transit farther from shore to open areas for offshore wind development³. Rerouting vessel traffic would potentially lead to a marginal increase in the cost of shipped goods. Yet cost savings from cheaper electricity generated by wind projects built closer to shore in shallow waters previously occupied by vessels could outweigh this increase.

As the analysis involves both an established and a future activity, we apply certain assumptions about the size and location of future WEAs. We assume that during the next several years, the currently designated WEAs and other accessible areas with minimal spatial conflicts and water depths of less than 30 meters would house wind projects. Then, to prevent conflicts, developers would have to build farther from shore, where costs are significantly higher. Without changes in ship traffic patterns, these far-shore sites would need to be developed if the US is to meet the goal of deploying 54 GW of capacity by 2030. Alternatively, we suggest that near-shore space could be reallocated for energy development. This would require the

³ The notion of directing vessels to transit farther from shore on coastwise trips has been suggested previously. A report by the Oil Spill Task Force (2002) argues that tankers carrying crude oil coastwise anywhere between San Diego and Cook Inlet on the US West Coast could voluntarily transit at least 50 nm from shore to reduce the risk of oil reaching the shore in case an accident occurs.

reassignment of some of the near-shore shipping patterns to new traffic patterns farther from shore.

In our study, net societal benefits are estimated in the following way. Societal costs are measured based on additional costs that would accrue to the shipping industry as vessels travel farther from shore. These costs include increased operating, fuel and capital costs as well as the value of health and environmental damages from the increased emissions of air pollutants CO₂, NO_x, SO_x and PM generated during rerouting. Societal benefits are calculated based on the savings of capital expenditures, operating costs and debt payments, associated with constructing and servicing wind projects at different distances from shore. With shallower waters and closer proximity to shore, the reduction in cost would come from cheaper foundations, lower transmission cable costs, and lower transportation and operations and maintenance costs. Additional societal benefits would come from the value of reduced air emissions, as vessels transporting wind turbine components would have shorter voyages using less fuel.

The study focuses on the large deep-draft ships traveling between the port areas of New Jersey/New York, Delaware Bay and Chesapeake Bay (Figure 1). Deep-draft vessels include container ships, bulk carriers, general cargo, tankers and vehicle carriers. These vessels represent foreign vessel traffic, which comprises the majority of all large ship transits in the area. Less than 1,500 annual ship transits would be affected. We propose to reroute these ships traveling along the current habitual traffic route (HTR)⁴ at 37 km (20 nautical miles) from shore to transit at 59 km (32 nautical

⁴ Habitual traffic route or pattern (as discussed in Vanderlaan et al. 2009) is “the self-determined principle path, route, or lane in the ocean traveled by vessels and connects

miles) from the coast. An average increase in the length of vessel voyage would be 18.5 km (10 nautical miles). The vessels would be directed within an established far-shore HTP used by ships transiting between destinations outside of the study area (Figure 1.1).

We recognize that the proposed policy is likely to affect other vessel types. These effects are not estimated for several reasons. Tugs and barges utilize a near-shore route outside of the affected HTP that we propose to modify⁵. The effects on passenger ships and fishing vessels are not estimated as their cost structures, particularly labor costs, differ significantly from those of the deep draft vessels. However, we emphasize that the additional costs could be incurred as other vessel types are forced to reroute if the proposed policy is established.

one or more geographic locations, such as a traffic separation scheme (TSS, not self-determined) and a port” (Vanderlaan et al. 2009, p. 276).

⁵ For tugs and barges transiting within the affected route, an inside corridor could be created to ensure their navigational safety.

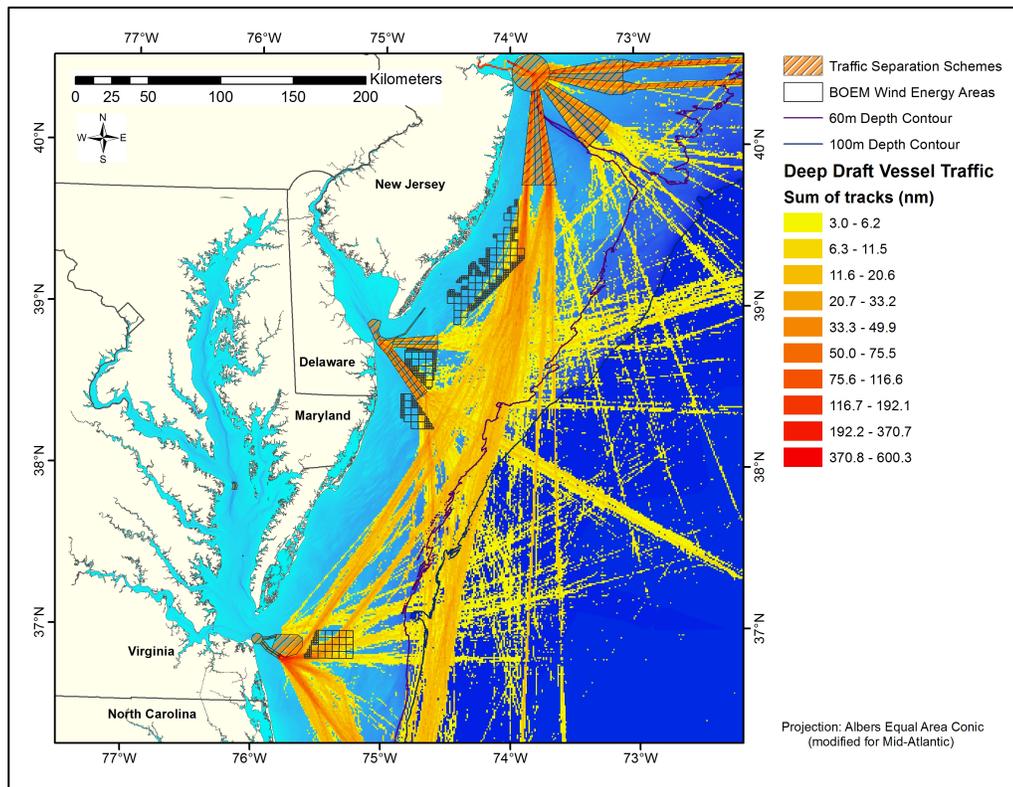


Figure 1.1: Relative density of vessel traffic in the Mid-Atlantic and WEAs

1.4 Organization of the Thesis

The thesis is organized as follows. Chapter 1 provides introduction, background, scope and objective of the study. Chapter 2 highlights most relevant research on economic effects of vessel rerouting, relationships between distance and water depth and cost of offshore wind projects, and social costs of air pollutants. Chapter 3 introduces framework and methodology used in the study, emphasizing assumptions and reasoning behind spatial data and cost-benefit analyses. Chapter 4 details key findings. Chapter 5 provides a discussion of key results, policy implications and suggests areas for future work.

Chapter 2

LITERATURE REVIEW

2.1 Introduction

This chapter reviews existing studies and methods on 1) measuring economic effects of vessel rerouting, 2) relationship between offshore wind cost and distance and water depth, and 3) social cost of air pollution. Here, we provide an overview of the relevant literature.

2.2 Research on Vessel Rerouting and Its Economic Impacts

The majority of research on rerouting vessel traffic has been performed in the context of reducing probability of vessel strikes of whales. Some of these studies analyze the economic effects the proposed rerouting or slow steaming would have on commercial shippers. The effects of vessel rerouting are also assessed in the context of ships avoiding pirate-ridden areas off the coast of Somalia. Yet, no studies specifically estimate the economic effects of directing vessels to transit farther from shore to open areas for offshore wind projects.

2.2.1 Vessel Rerouting Using Spatial Data Analysis Tools

Few studies are available on quantitative methods of rerouting vessels to accommodate another ocean use. Vanderlaan et al. (2009) evaluates the probability of vessel encounters of the North Atlantic right whales and suggests modifying a vessel traffic route to reduce the probability of vessel-whale strikes. Vanderlaan and

colleagues (2009) calculate ship traffic density using the International Comprehensive Ocean-Atmosphere Data Set (ICOADS) (ICOADS, National Center for Atmospheric Research, Boulder). They define the most dense vessel traffic routes as Habitual Traffic Patterns (HTP) - “the self-determined principle path, route, or lane in the ocean traveled by vessels and connects one or more geographic locations, such as a traffic separation scheme (TSS, not self-determined) and a port” (Vanderlaan et al. 2009, p. 276). Vanderlaan et al. (2009) spatially reallocate vessels to another HTP considering bathymetric limitations and the existing TSSs to ensure that the shift would not compromise safe navigation.

Another study evaluating the need for vessel rerouting to reduce the probability of vessel-whale strikes in the Bay of Fundy was also conducted by Vanderlaan et al. (2008). The authors estimate that the relative risk of lethal collision can be reduced by 62% if the TSS that intersects a Right Whale Conservation Area was amended. This study contributed to the adoption of TSS amendments and seasonal area to be avoided (ATBA) by the International Maritime Organization (IMO) (Vanderlaan et al., 2008). Importantly, neither of the studies includes economic analysis in their proposed decision-making strategies. However, they illustrate ocean management decisions when vessels are rerouted to avoid areas that have high conservation value.

2.2.2 Economic Impact of Vessel Traffic Rerouting

Studies on economic impacts of vessel traffic rerouting analyze the economic effects of slow steaming or impacts of fuel costs on maritime operations. Kite-Powell and Hoagland (2002) estimate the costs of unanticipated and expected additional transit time for potential dynamic management measures, for which vessels would reduce speed to 10 knots for some period of time. The costs are estimated for vessels

of different cargo type, size and ship type. The study predicts an average cost of \$2,350 per affected port call due to delays (Kite-Powell and Hoagland, 2002).

Notteboom and Vernimmen (2009) create a cost model to understand the effects of fuel costs on cargo liners, considering capital and operating costs.

A study by the NMFS (2008) evaluates direct and indirect economic impacts of the operational measures to reduce whale strikes on the US East Coast maritime activity. Several alternatives are assessed. The alternative imposing a speed reduction of 10 knots, an establishment of a Dynamic Management Area⁶, and recommended route designations is found to have the largest total economic effect (NMFS, 2008). The total economic impact of the alternative was estimated at \$359.7 million annually (ibid). The direct effects also included multiple port calls and higher intermodal costs, as well as indirect impacts from diversion of traffic to other port areas and the associated impact on income and employment (NMFS, 2008).

Additionally, a document discussing the impact of proposed modification of traffic separation scheme in the Bay of Fundy was submitted by Canada to the IMO in 2002 (NMFS, 2008). The traffic lanes of the TSS are shifted from the area with high density of right whales to an area with lower density. This measure added 18 km for vessels calling at Eastport and Bayside (affecting 100 vessels per year) and 8 km for vessels calling at Saint John (affecting 600 vessels per year). The estimated effect on shipping was described as ‘minimal’ and was not quantified (NMFS, 2008).

⁶ A Dynamic Management Area would imply a creation of a circle with a radius of at least 5.2 km around the location of each whale sighting. The radius is adjusted based on the number of observed whales in the area. A buffer is also drawn. If any circle or a group of circles includes three or more right whales, the core area and its surrounding waters would be a candidate for the establishment of a DMA zone (NMFS, 2008).

A study by Kite-Powell (2005) illustrates direct and indirect economic impacts of the hypothetical loss of vessel calls to the Port of Boston that may result from delays and added costs imposed by the management measures to protect the right whales. The study estimates the economic effects of the four scenarios where certain operators choose to longer call at the Port of Boston. While illustrative of the overall importance of evaluating economic effects of changes in vessel routing, slow steaming or operators deciding not to call on certain ports, the studies provide limited guidance on estimating added costs.

Betz et al. (2011) provide the most comprehensive methods for calculating added costs of vessel rerouting to reduce probability of vessel strikes to whales. The researchers estimate the economic effects of speed reductions and rerouting on the vessels transiting the Santa Barbara Channel. The model calculates costs that would be incurred from a longer voyage or additional time spent at sea during a transit at a slower speed (Betz et al., 2011). The methods on estimating fuel use, vessel operating costs, and additional hourly costs of delay and cost of delay from Navy operations are provided.

On an international scale, ship rerouting is often discussed in the context of avoiding pirate-ridden areas especially off the coast of Somalia. Bowden et al. (2010) estimate that the cost of rerouting when ships avoid the Horn of Africa, traveling an additional 4,345 km on the longer route around the Cape of Good Hope. The authors estimate that the shipping industry spends approximately \$2.3 to \$3 billion annually to avoid piracy-ridden areas. The cost model used in the study was consulted and provided a useful background for this study.

2.2.3 Studies on Components of Vessel Added Costs

To estimate specific components of added vessel costs, we consult other studies. Corbett et al. (2009) serves as a basis for estimating the added fuel cost. The authors evaluate whether speed reduction can be a cost effective mitigation option for ships calling on US ports. The study estimates economically efficient speeds for specific routes, and provides methods for estimating fuel usage and CO₂ emissions. The per-trip fuel use of a ship is estimated by adding fuel used by main and auxiliary engines. For the main engine, the fuel consumption per trip follows the cubic law of design speed and operational speed (Corbett et al., 2009) Fuel consumption of the auxiliary engine, which does not follow the cubic law, is added to that of the main engine. Fuel usage for original and rerouted vessel trips for our model is estimated based on this methodology.

Estimating operating costs and effect of increasing voyage length or time is also a common practice within the US Army Corps of Engineers (USACE). Horn et al. (2010) discuss categories of operating costs for deep-draft vessels based on vessel sizes (deep sea tankers, dry bulkers, general cargo vessels and containerships). Knight and Mathis (2010) provide a more detailed guide to estimating vessel operating costs for deep-draft vessels (DDVOC), but do not provide specific estimates. The report also discusses methods to estimate vessel capital costs, yet no values are listed.

Thus, we rely on the data on operating costs from Wilkinson et al. (2011). Operating costs are the ongoing expenses related to the day-to-day operation of the vessel and are often considered to be variable costs. They consist of six categories: crew wages and medical expenses, provisions, lubricating oils and stores, spares, maintenance and repair, insurance, registration costs, management fees and sundries (Wilkinson et al., 2011). Fuel expenses are not included, as these are a part of voyage

costs (Stopford, 2011; Betz et al., 2011). The operating costs are listed for 26 types of vessels (Wilkinson et al., 2011). Data was collected from 2,600 ships in 2010; we bring these values into 2012\$. As the annual and daily costs are listed, we calculate hourly operating cost using this data.

A study by the US Department of Transportation also provides data on vessel operating costs but is not used in our model (US DOT) (2011). The study compares US flag and foreign vessel operating costs for container, bulker, and Ro-Ro vessels. Operating costs vary by vessel type, age, trade route and labor agreements and increase with age, as older ships require more maintenance (US DOT, 2011). Crew costs are also determined by the size of the vessel, age, and by the employment practices of the vessel flag state. The costs for US-flag vessels are approximately 2.7 times higher than that of foreign-flag ships. Since our data on affected vessel transits represents only the vessels participating in foreign commerce, the number of the affected US-flag ships is not known. Therefore, these data are not used in the model.

2.2.4 Other Transportation Modes and Impacts of Rerouting

Even though not directly applicable to modeling effects of vessel traffic rerouting, it is also useful to consider the literature evaluating impacts of rerouting or transit disruptions of other transportation modes. Hu (2008) provides a methodology and a theoretical framework to estimate economic impact of freight disruption due to highway closure. The study classifies three types of costs: private operating costs for carriers, scheduling and logistics costs, and indirect costs for the market.

For measuring private operating costs, which are of the most interest to our study, Hu uses resource saving method. It is based on the marginal cost associated with unit time increase, and is used to estimate private operating costs for highway

carriers for one mile. The method is commonly used to estimate the value of commercial vehicle time savings. The research considers the value of travel time in freight transport and proposes adjustments to other methodologies used to estimate the economic effects of freight disruption due to highway closure. Hu's estimate of economic losses due to rerouting and delay of shipments represent an approximation of factors that need to be considered for vessel rerouting. However, as vessels in our study will not be rerouted unexpectedly but are assumed to have perfect information regarding the location of wind projects, value of time is calculated differently.

Some of the other studies concentrate on the value of travel time in passenger transport (Hu, 2008). A few studies suggest that same approaches can be applied to measuring the value of time in freight transport. However, this study will not be estimating the value of travel time or measure the unit value of the average delay for ships, as estimating these effects is beyond the scope of this paper.

2.2.5 Impacts on Collision and Allision Risk due to Rerouting

We acknowledge that the proposed vessel rerouting can increase the risk of collisions and allisions. The greater risk can come from the mix of vessels of different sizes and operating speeds, as well as the increased vessel density in certain areas. Sufficient separation distances between offshore wind projects can significantly reduce the risks of collisions between vessels and wind projects. The US Coast Guard is currently evaluating several proposed buffer zones around wind projects ranging from 0.5 – 10 nm (USCG, 2012). Furthermore, the risk of allisions between ships could be reduced if vessels use appropriate navigational measures to maintain safe distances while passing each other. The increased risk of collisions and allisions due to

vessel rerouting is a serious concern, but is not evaluated here due to the limited scope of this study.

2.2.5.1 Selected Models and Data Sources

Fuel usage per vessel trips is estimated based on methodology in Corbett et al. (2009). The cost of metric ton of fuel is based on the average market prices for 2012. Operating costs are calculated using the data in Wilkinson et al. (2011) and by multiplying the number of added hours by the hourly operating costs (NMFS, 2008).

2.3 Research on Offshore Wind Power Costs

The cost of offshore wind energy depends heavily on geographic conditions, particularly water depth and distance from shore. Bilgili et al. (2012), Green and Vasilakos (2011), Prasslet and Schaechtele (2012), Blanco (2009), Jacquemin et al. (2011), Crown Estate (2011) and BVGA (2012) emphasize the impact of these factors on the cost of wind energy. KPMG (2010) and RenewableUK (2011) also mention these factors but do not provide specific cost estimates. This portion of the literature review highlights major studies that specifically investigate the cost relationship between depth and distance.

2.3.1 Wind Project Components and Costs

Dicorato et al. (2011) formulate a model for assessing total expenditures needed for offshore wind projects depending on project layout. Greater distance from shore is commonly paired with deeper waters, leading to the need for larger and more expensive foundations. Thus, foundation cost can reach up to 29% of total cost. Projects located farther from shore also require longer transmission cables and potentially an offshore substation, potentially reaching 11% of total cost. Based on

reviewed studies, Dicorato et al. (2011) provide a methodology and discuss their investment model to calculate foundation costs, transmission and electrical systems, grid interface costs and development costs. While useful in providing insight into investment costs for wind projects, the study only assessed the cost of monopiles, while our scenario involves projects in deeper waters populated with jacket and floating foundations.

Snyder and Kaiser (2009) estimate costs and benefits of offshore wind compared to those of onshore wind power and conventional electricity generation. They develop cost functions for offshore wind projects based on the available data from projects between 2000 and 2008. To predict capital costs, Snyder and Kaiser (2009) develop a multiple regression model based on predictor variables: total project capacity, water depth, distance to shore, turbine size, construction year and number of machines. Similarly to experience with offshore oil and natural gas, greater depth leads to higher cost foundations and larger installation vessels. Having projects farther from shore will not only influence transmission costs, but also increase the distance and the number of trips installation and maintenance vessels will have to travel to the site.

A report by ODE (2007) (often used by subsequent studies for cost inputs) evaluates trends in future costs of offshore wind generation and potential cost reductions, and identifies six parameters as the most influential factors in total project costs. The cost of offshore wind projects depends largely on the cost of raw materials, especially steel, as those are determined by the market (ODE, 2007). Also, distance from shore defines the number and length of trips a vessel will have to make to complete the project, influencing the total cost (ODE, 2007).

Another study that emphasizes the relationship between offshore wind costs and water depth and distance to shore is the report by the European Environment Agency (2009). The study provides data on the capital and O&M costs based on data for wind projects built internationally. Papalexandrou (2008) uses the data from EEA (2009) to argue that with distance, offshore investment cost can increase from €1,800-2,878/kW. For foundations (in this case only monopiles are assessed) the costs also increase from €300,000/MW for 15 m depth to €1,000,000/MW for 40 m depth (Papalexandrou, 2008; EEA, 2009).

Prassler and Schaechtele (2012) also emphasize that water depth and distance affect cost of offshore wind energy. Using the estimates from EEA (2009), they model more detailed scale factors and update the cost data. They assume a starting value of €3,800/kW for a project built 40 km from shore in 30 m depth (Prassler and Schaechtele, 2012). Table 2.1 summarizes the scale factors between cost and distance and depth.

Table 2.1: Scale factor for cost increases as a function of water depth and distance to shore

Distance (km)		20-30	30-40	40-50	50-100	100-200	>200
Depth (m)	10-20	1.043	1.065	1.086	1.183	1.408	1.598
	00-30	1.113	1.136	1.159	1.262	1.501	1.705
	30-40	1.290	1.317	1.344	1.464	1.741	1.977
	40-50	1.457	1.487	1.517	1.653	1.966	2.232

Source: EEA, 2009

BVGA (2011) report complements the National Grid (2011) and Renewable UK (2012) reports and highlights past and current developments in offshore wind

industry in the UK. The report estimates costs for large projects with different turbine ratings, water depths (up to 45 m) and at different distances from shore (up at 150 km). Costs per kg for steel for jackets and pin piles are listed at £3.2/kg and £1.4/kg. Installation costs for foundations, cables and turbines for different sites are also provided.

Jacquemin et al. (2011) consider the opportunities and spatial constraints of developing wind projects in the North Sea and identify the factors that strongly influence the cost of offshore wind energy. The study provides a variety of cost estimates for turbine foundations (jacket and floating), transmission cable costs, installation and O&M costs based on several distances from shore. Approximate weights for jackets and Tension Leg Platform (TLP) – a type of floating foundations that can be used in 50 – 150-meter depths – for a generic 5 MW turbines are provided. Fatigue or extreme loads are not applied; hence the final weights can be higher or lower than projected. As this is the only study that provides weights of jacket and floating foundations that can support a 5 MW turbine modeled in our study, these weight estimates are used in our model.

In a report for National Renewable Energy Lab (NREL), Elkinton et al. (2012) provide a comprehensive review of foundation weights and manufacturing costs, transmission cable costs, and installation vessel requirements. Elkinton et al. (2012) provide weight functions used to estimate weights of jacket foundations for different water depths. The data used to develop weight functions comes from previous Garrad Hassan designs⁷. The jacket weights are non-location specific, as the weight functions

⁷ Garrad Hassan was one of the contractors for this study, providing proprietary data for the model.

do not incorporate soil profiles, metocean conditions, etc. Extreme wave and wind loads have been applied, and thus the estimated weights are slightly more conservative. However, even though these are the newest estimates, no foundation weights to house 5 MW turbines are provided. Elkinton et al. (2012) also provide estimates for cost of fabricating steel for jackets: \$5,500-7,000/metric ton. In our model an average of \$6,250 is used.

Weights for jacket piles are not estimated due to the limited data on the weight increase with water depth. Also, available studies claim that pile weight is determined largely by soil conditions rather than water depth (Jonas, 2009). Elkinton et al. (2012) also argue that with the increase in water depth and no changes in other variables, jacket pile weights tend to remain relatively constant. As we are only interested in quantifying the change in the weight and costs of components at different water depths, we assume the jacket pile weights remain constant at all sites. Therefore, this component is excluded from the analysis.

2.3.2 Distance from Shore and Transmission Cable Options

Depending on the distance from a wind project to the shore, different cable options can be employed. The precise cut-off distance for which HVAC or HVDC transmission cables are used varies in different studies. Green et al. (2007) suggest that HVAC cables are more cost-effective for projects located less than 50 km from shore. Between 50 km and 80 km, HVAC and HVDC are likely to cost the same, with HVDC being cheaper for projects farther than 80 km offshore (ibid).

Elkinton et al. (2012) suggest that for medium-sized (up to 700 MW) projects less than 60-100 km from shore, high-voltage alternating current (HVAC) cable systems are used. HVAC systems are employed as they have lower capital costs than

high-voltage direct current (HVDC), which requires secure converter infrastructure needed to convert power coming from the AC cables from the turbine array in order to transmit it to the onshore grid (ibid). However, the HVAC cable costs are higher than that of HVDC lines (Bresesti et al., 2007). On the other hand, HVDC cables have significantly lower losses, as there is no resonance between the cables and other HVAC equipment (Bresesti et al., 2007). Thus, HVDC systems are employed for larger projects farther from shore.

2.3.2.1 Transmission Cables Cost

This subsection reviews studies highlighting the differences in costs of HVAC and HVDC cables. As transmission cables are manufactured specifically for particular projects, the estimates provided here are generic. However, they are meant to provide a preliminary insight into the cost reductions associated with bringing offshore wind projects closer to shore.

An NREL study by Green et al. (2007) develops a simplified model that estimates the performance and costs of transmission systems. Cable procurement amounts to \$755 - \$860/m for 630 mm² HVAC cable. Cable shipping and installation costs amount to \$94/m for cable laying operations and \$58/m for transporting the cable via freighter from Europe (ibid).

Elkinton et al. (2012) suggest that the cost of procuring XLPE HVDC cables ranges from \$1,300,000/km to \$3,000,000/km. In our model, we use an average of \$2,150,000/km. For HVAC transmission cabling, the costs range from \$1,056,000/km - \$1,200,000/km (220 kV 1000 mm² cable). We use an average of \$1,128,000. Cable installation costs range from \$550,000 - \$800,000/km (Elkinton et al., 2012). An average of \$675,000/km is used in the model.

Dicorato et al. (2011) list the cost of a 630-mm² 150-kV HVAC cable at 673,600 €/km. Installation, cable laying and transport services for the cost of submarine cables is estimated at 720,000 €/km (Dicorato et al., 2011).

Renewable UK (2012) highlights differences in investment and development costs for near- and far-shore projects with different transmission system options. Based on the National Grid (2011) report, the study lists a mid-point range of £625/m for HVAC 220kV 3-core subsea cable, with £0.9 m/km for installing two cables in two separate trenches. For HVDC 320 kV 1200 mm (extruded XLPE cable), a mid-point of £375/m installed in one trench at £0.7m/km is listed (Renewable UK, 2012).

2.3.2.2 Transmission System Losses

Over 20 years of project operation, even small differences in transmission losses between the HVDC and HVAC technologies can lead to substantial differences in energy output (Negra et al., 2006). The next subsection summarizes the research on transmission losses.

Dicorato et al. (2010) argue that HVDC technology is less dependent on distance and has lower losses, though has high initial cost. However, the authors do not provide a detailed discussion of losses or methods to estimate them. de Alegria et al. (2009) list converter losses from HVDC LLC (1-2%) and HVDC VSC (4-5%) but do not provide line losses.

Green et al. (2007) estimate transmission losses as a function of the power generated by the wind project and the length and size of the transmission cables. Their model also accounts for wind turbine size, the number of machines, turbine array configuration and spacing, and distance from shore. However, since the model is only

run for one 500 MW project, the direct relationship between the amount of power lost due to distance cannot be sufficiently established.

Negra et al. (2006) compare transmission losses as a percentage of wind farm production for one HVAC and two HVDC solutions. Their model is based on Brakelmann (2003). The transmission losses are determined for a 500 MW and a 1,000 MW project at various distances to shore (up to 200 km) and an average wind speed of 9 m/s. Negra et al. (2006) argue that HVAC system provides the lowest losses for a distance of up to 70 km for the coast (depending on the size of the project). Reidy and Watson (2005) list conversion and line losses for HVAC and HVDC, yet precise losses per km cannot be accurately extracted.

As previous studies do not provide enough detail to derive transmission cable losses per km, we rely on data provided by Atlantic Wind Connection (AWC), a transmission company planning to build a subsea cable off New Jersey. Table 2.2 lists losses for HVDC (320 kV) and HVAC (230 kV) cables. These data are optimized for 320 kV 1000MW HVDC and 230 kV HVAC 250 MW capacities. For actual projects, losses for different sizes of cables will vary slightly. Yet these estimates allow us to calculate the amount of power lost during transmission and monetize its value.

Table 2.2: Losses in MW/km based on three cable options. The losses are optimized for a 320 kV 1,000 MW cable.

	Losses in MW/km	
320 kV dc cable, 1000 MW	0.0424	based on 2400 mm ² conductor
320 kV dc cable, 500 MW	0.0094	based on 2400 mm ² conductor
230 kV ac cable, 250 MW	0.0718	based on 800 mm ² conductor (4 circuits for 1000 MW)

Source: AWC (2012), personal communication, October 2012

2.3.3 Wind Transportation Cost

Another important factor influencing capital cost of wind projects is distance traveled by construction vessels from staging ports onshore to project sites.

Components are transported with large jack-up vessels (and sometimes barges) called feeder vessels, capable of jacking up to achieve stability in deep water. After jacking-up at the project site, components are unloaded from them with installation vessels. These feeder vessels are often towed to the site by one or more tugs. Purpose-built vessels specifically designed for transporting and installing components can also be used, but are significantly more expensive. These vessels are more likely to be using the European market. With longer voyages, both feeder vessels and tugs have to be rented for longer periods of time, increasing the cost of wind projects.

While numerous studies suggest that transportation cost increases with distance from shore, research quantifying and monetizing these impacts is sparse. So are the data on vessel day rates. Day rates represent operating expenses that accrue to a vessel

operator, including all costs beyond capital expenditures. These include labor, insurance, fuel, maintenance and administrative costs (Kaiser and Snyder, 2012).

Studies estimating or providing day rates for vessels servicing European markets (BVGA, 2012; Kaiser and Snyder, 2012) suggest that due to high demand in Europe, vessel day rates are significantly higher compared to the projections for the US market. Thus, BVGA (2012) lists \$241,000/day for a self-propelled jack-up. SeaJack vessels used to install turbines at Walney and Greater Gabbard wind projects in the UK signed contracts for \$148,000 and \$176,000/day (without mobilization costs) (Kaiser and Snyder, 2012).

As the US market is still immature, the supply of specialized vessels is likely to remain limited. Restrictions on the use of non-US flag vessels imposed by the Jones Act also limit the number of vessels that can assist with transportation and installation of offshore wind projects. Therefore, projections on the future day rates for ships servicing the US market are used in our model. Kaiser and Snyder (2012) model day rates for installation vessels in the US based on whether they are leased or built and owned by the developers. The expected day rate values for lift boats is \$35,000; jack-ups - \$64,000, and for special purpose installation vessels (SPIV) - \$134,000 (ibid). Elkinton et al. (2012) also list day rates for US self-propelled jack-up vessels at \$60,000. An estimate received from Weeks Marine - a US marine transportation contractor - also lists \$60,000 as a likely day rate for US vessels used to transport components to the wind project site (Weeks Marine, 2012, personal communication).

In our model, we assume that wind turbine components (rotors, nacelles, blades, and towers) and foundations will be transported with US feeder vessels. These are assumed to be smaller jack-up vessels that have been cleared of cranes and other

deck equipment or special purpose vessels built for the project that would be able to jack-up while components are unloaded. We assume that these vessels will not be self-propelled and be towed to project sites with large 6,000-horse-power (HP) tugs. Based on personal communication with Weeks Marine, the tug day rate is assumed to be \$8,111 (in 2012\$)⁸. Weeks Marine also provides fuel usage and cost data. For transporting turbines installed on floating foundations, we assume that two 6,000-HP tugs will be used to tow each unit⁹. Vessel mobilization costs are not included.

2.3.4 Operating and Maintenance Costs

The operation and maintenance (O&M) costs comprise a significant portion of expenses throughout 25 years of project operation. O&M costs include regular scheduled maintenance as well as servicing turbine breakdowns. As with longer distances from shore, the time needed for the service team to travel to the site increases. Also, depending on the distance from coast, onshore or offshore O&M bases are used. Offshore bases are serviced with helicopter or vessel support.

O&M costs are difficult to locate. We rely on the only available estimates from Jacquemin et al. (2011). The study models the O&M costs based on turbine reliability, number of turbines in service, wind and climate conditions, assumptions regarding the

⁸ These estimates are for budgetary purposes and are not for a specific bid. Thus, these costs are approximate, and as they depend on many factors, these costs are only a projection of future values (Weeks Marine, Rick Palmer, December 2012).

⁹ The tugs are assumed to be 6,000 HP based on the personal communication with Rick Palmer, Weeks Marine. He suggested that for construction of far-from shore projects using a larger tug reduces the operating risk when the weather conditions deteriorate. Also, as we assume that 5 MW turbines will be used, as well as large jackets, 6,000-HP tugs would be able to transport several components at the same time.

location of the O&M base (onshore/offshore), type and cost of supporting vessels or helicopter support, and number and annual cost for the team of technicians. These O&M estimates are converted into \$/MW/annum and listed in Table 2.3 below.

Table 2.3: Cost of O&M for offshore wind projects at different distances from shore.

Distance to shore, km	\$/MW/annum
20 km - Onshore O&M base	\$73,947
50 km - Onshore O&M base	\$76,297
50 km - 150 km - Offshore base w helicopter support	\$88,066
>150 km - Offshore base, no helicopter support	\$91,766

Source: Jacquemin et al. (2011)

2.3.5 Capital Cost Financing for Wind Projects

Offshore wind projects can cost hundreds of millions of dollars and are extremely capital intensive, with the majority of expenditures occurring during construction (Manwell et al., 2009). Consequently, a developer often makes a down payment of 10% or 20% and finances the rest (ibid). Financing would come from a bank or from investors, who will expect a return on the loan. In case of a bank, the return is referred to as interest. The cumulative interest can add up to a significant amount over the life of the project (ibid). Shallow water projects would be cheaper to

build and therefore, the debt incurred would be lower. Thus, we monetize this reduction in debt as a portion of benefits from the proposed vessel rerouting.

Wind project financing structure depends on multiple variables and is often project specific. According to a report by NREL, at least six financial structures exist, with all-equity or project-level debt financing (Cory and Schwabe, 2009). We do not perform an extensive literature review regarding wind project finance modeling as an all-encompassing modeling of this complex subject is beyond the scope of our analysis. Therefore, capital cost financing is modeled based on simplified assumptions. We assume a debt rate of 7.5%¹⁰ (Massachusetts Department of Public Utilities, 2012) and the payback period of 15 years, as suggested by Levitt et al. (2011)¹¹.

¹⁰ Levitt et al. (2011) suggest using a Weighted Average Cost of Capital (WACC) instead of strictly the debt rate. WACC is “the weighted average of the required returns on the firm’s debt and equity as determined by the market... This rate can be taken as the minimum rate of return required to fund a project” (Levitt et al., 2011, p 6413). They come up with a WACC of 9.8%. However, when this WACC is adjusted to real dollars (reduced by 2%) it closely resembles the Cape Wind financing rate of 7.5%. Therefore, to avoid the added complexities of bringing considerations regarding equity into the model, we assume the debt rate obtained by Cape Wind. Additionally, we do not include Production Tax Credits (PTC) or Investment Tax Credits (ITC) in our model. Including PTC or ITC would bring additional complexity and uncertainty into the model, as it is not clear whether these programs would exist in 2020 and further in the future. Also, tax incentives and loan guarantees are transfers - transactions where money moves around while no economic value is created or consumed. Therefore, these are excluded from the analysis.

¹¹ Equity has a debt term of 10 years, following Production Tax Credits (PTC) (Levitt et al., 2011).

2.3.6 Other Studies on Cost of Offshore Wind Energy

Other studies that model cost of offshore wind energy but do not provide a detailed breakdown of factors influencing costs at different distances and water depths:

- Musial and Butterfield (2004) – create a model that predicts long-term cost-of-energy (COE) trends for US projects; all of the estimates are based on monopile foundations and less than 30 m water depth.
- Fingersh et al. (2006) - provide approximate cost estimates based on 500 MW, 3 MW turbines, installed 8 km from shore in 10-meter water depth. The authors suggest using certain formulas to estimate foundation costs, cost of transportation, installation and O&M. The formulas however are fairly simplistic and do not fully emphasize the relationship between distance and water depth and capital and operating expenditures.
- Nielsen (2003) provides the price of 250-300 €/kW and 2% increase per meter of additional water depth based on experience in Denmark.
- Manwell, McGowan and Rogers (2009) provide estimates of average investment costs related to offshore wind projects Nysted and Horns Rev. Cost estimates are listed in €/kW and are concentrated on assessing costs for the North Sea.
- Green and Vasilakos (2011) review various economic support policies in Europe and provide estimates of costs of offshore wind energy. They cite the report by the European Environment Agency (2009) that provides data on the relationship between installation costs and water depth.

- Blanco (2009) presents findings of the recent study that analyzed generation costs of existing offshore wind projects, factors that are most influential and how these are projected to change.
- Herman (2002) provides formulas for estimating transportation and installation costs with different vessels for different components and transmission cables. Cost of delays due to bad weather is also included. Time to site for vessels is taken into account, but assumed to be the same for projects at 10 km and 50 km from shore. Day rates for vessels are not listed.

2.4 Selected Models

To estimate cost of offshore wind projects for our status-quo and alternative scenarios, a combination of methods are used. The cost of jacket foundations is calculated based on weights for jackets supporting 5 MW turbines in Jacquemin et al. (2011). The cost per ton for manufacturing steel for jackets comes from data in Elkinton et al. (2012). The cost of floating foundations (TLP) is based on Jacquemin et al. (2011) who provides estimated weights and costs of floating structures, cables and anchors. Transmission cable costs and cable installation costs are estimated based on data in Elkinton et al. (2012). Transmission losses are estimated based on MW/km lost data provided by Atlantic Wind Connection (AWC). Transportation costs are calculated using day rates and fuel usage for tugs and feeder vessels provided by Weeks Marine. Operation and maintenance costs are calculated based on modeled estimates of \$/MW/year in Jacquemin et al. (2011).

2.4.1 Social Cost of Air Pollutants

Vessel-generated emissions constitute 18-30% of the global nitrogen oxide (NO_x) pollution, 9% of the world's sulphur oxide (SO_x) emissions (Vidal, 2009), and approximately 3% of global climate change emissions (Eide et al., 2011). As approximately 70% of ship emissions occur within 400 km of the coast, vessel traffic affects air quality in coastal communities, reaching considerably far inshore (Corbett et al., 2007; US EPA, 2010). For example, emissions from vessels contribute between 5-30% of SO₂ concentrations in coastal regions (Capaldo et al., 1999).

As during their longer voyages, the vessels traveling between the Mid-Atlantic ports would generate more emissions of SO_x, NO_x, particulate matter (PM) and CO₂, we estimate their social costs – the value of the health and environmental damages they would produce. This section provides a summary of health and environmental impacts of emissions and highlights the methods on estimating the emissions based on the amount of fuel used. It also lists available estimates on the social cost per ton of these air pollutants.

2.4.1.1 Health and Environmental Impacts of Air Pollutants

A study by the US EPA (2009a) outlines the health effects of ship-generated pollutants in a proposal to designate an Emission Control Area (ECA) for portions of the US and Canada coastal waters. Exposure to SO₂ is likely related to bronchoconstriction, decreased lung function and cardiovascular diseases (EPA, 2009a). Exposure to NO₂ may have various respiratory effects and can potentially decrease lung function. Exposure to PM_{2.5} is related to premature mortality from cardiopulmonary diseases, increased respiratory symptoms, cardiac changes and decreased lung function (EPA, 2009a; EPA 2009b).

Due to the imprecise science of distinguishing human health impacts that are caused specifically by SO_x and NO_x instead of their PM derivatives, the report does not quantify the health effects from exposure to direct emissions of SO_x and NO_x from ships separately (EPA, 2009a). Other studies are used to provide cost estimates of external effects of vessel-generated emissions.

While CO₂ emissions do not cause direct health effects, it is one of the leading contributors to climate change, which will have far-reaching effects. The effects of climate change include accelerated sea level rise, heavy downpours, ocean acidification, reductions in ice and snow cover, intense heat waves, increased extreme weather events, such as droughts and hurricanes, etc. (US Global Research Program, 2009). Emissions of CO₂ from the maritime transport constituted 2.7% of total emissions in 2011 (IMO, 2011). Literature estimating the cost of climate change impacts concentrates on health effects, agricultural losses, tourism and sea level rise. Thus, in our studies, the social cost per ton of CO₂ represents these costs.

2.4.1.2 Quantifying Emissions from Ship Traffic

Several studies estimate or propose an approach to calculating the amount of CO₂, NO_x, SO₂ and PM emissions generated by the maritime transportation sector. In a study for the European Commission, Miola et al. (2009) propose a methodological approach for estimating both health and environmental impacts, which are assessed specifically in the context of climate change. Corbett et al. (2009) propose a methodology to estimate fuel usage per trip by main and auxiliary engines. Using these fuel usage estimates, emissions per ton of fuel are calculated. Corbett (2010) builds on work in Corbett et al. (2006) and provides vessel-specific estimates of emissions for cargo traffic traveling along the US coastlines. Growth scenarios are

applied to 2002 data to produce estimates for 2010 vessel traffic before international sulfur regulations came into effect. Also, a 2020 scenario with the global reductions in sulfur content in fuel in place is also modeled. The study provides fuel use rates and emission factors for different vessel types estimated for 2020 (Table 2.4) (Corbett, 2010).

Table 2.4: Emission factors in 2020, in g/kWh

Vessel types	Fuel Use (Specific Fuel Oil Consumption (SFOC))	NO _x	SO _x	CO ₂	PM
Bulk, Container, General cargo, Ro-Ro, Tankers	206	15.38	1.96	622.9	0.40

Source: Corbett (2010)

The IMO's (2009) report is one of the major sources of data for our study. The report analyzes vessel greenhouse gas emissions in 2007 and models projected emissions for multiple scenarios in 2020 and 2050. Scenarios are characterized according to differences in global economy, population, agriculture and land use. The report also discusses a methodology for quantifying emissions and provides emission factors (in kg/metric ton fuel equivalent) for vessels in 2020 and 2050 (Table 2.5). These are based on the default emission factors (with an exception on NO_x) by International Panel on Climate Change (IPCC) and by the UNECE/EMEP CORINAIR programme by the European Environmental Agency (EEA) (Thomas et al., 2002). These estimates are used in our model as we anticipate that the development contemplated here will not take place prior to 2020.

Table 2.5: Emission factors (kg/metric ton fuel equivalent) in 2020 (except for CO₂)

Pollutant	Emission factor
NO _x	61
SO _x	9.2
PM	1.7
CO ₂ (distillates)*	3.19

Source: Buhaug et al. (2009)

*Emission factors for CO₂ are in kg of CO₂/kg of fuel. These are adjusted for the calculations of emissions added during rerouting

2.4.1.3 Monetizing Emissions to Determine Social Costs

The value of health and environmental damages caused by air pollutants ranges widely. The available studies list estimated ranges for the social costs, while also emphasizing the uncertainties inherent in the calculations.

Wang and Corbett (2007) estimate the environmental benefits from reductions in emissions coming from the switch from high to low-sulfur fuel range from \$2,252 - \$22,143 per ton. Gallagher (2005) uses SO₂ abatement costs for European ships and US tradable permit prices for SO₂ and NO_x emissions to estimate economic damage costs for emissions from vessels that made US port calls between 1993 and 2001. Thus, external cost of SO₂ ranges from \$750 - \$4,208 per ton and NO_x – from \$1,700 to \$9,500 per ton (ibid). Additionally, Holland and Watkiss (2002) suggest that the external cost of a ton of NO_x is \$7,150. In their study, the cost of SO₂ emissions ranges from \$2,252-\$8,303 per ton (Holland and Watkiss, 2002). The study by the US EPA (2005) provides a range between \$2,300 and \$22,143. Holland and Watkiss (2002) also estimate the cost of PM_{2.5} (the finer particle of particulate matter

emissions) to be \$14,000 (EU-25 average) (Faber et al., 2012). Matthews and Lave (2000) list estimates between \$1,454 and \$24,786 per ton of PM₁₀ (Boardman et al., 2011, values in 2008\$).

A report by the EPA (2010) provides estimates of the “social cost of carbon” (SCC), which is an estimate of the value of damages avoided in a particular year if a ton of CO₂ is not emitted¹². EPA (2010) compares three integrated assessment models that use different discount rates to estimate cost per ton of CO₂ between 2010 and 2050. At a 3% discount rate, the average social cost of CO₂ is estimated at \$21.4 per metric ton in 2010 and \$44.9/ton in 2050 (2007\$). Interagency Working Group on Social Cost of Carbon (2013) recently updated the estimated value of the social cost of carbon, which increases annually until 2050. The report lists a cost of \$36 per ton of CO₂ (in 2007\$) in 2013, assuming a 3% social discount rate. This value is used in our model after the estimates have been brought to 2012\$.

Recognizing the uncertainty associated with these social costs, we perform a sensitivity analysis using the high values for each air pollutant.

2.4.1.4 Emissions from Transportation of Offshore Wind Components and O&M

A very limited amount of literature is available on emissions produced during transportation of components and O&M. No specific estimates of the emissions produced by vessels transporting turbines and foundations or methods for calculating

¹² The SCC includes estimates of damages from climate change associated with effects on human health, changes in net agricultural productivity, and property damages from higher flood risk (US DOE, 2012). However, it is likely that the value underestimates the value of damages (Pachauri and Reisinger, 2007) as not all damages are included.

the emissions exist. Therefore, we use the available maximum daily fuel used by tug boats that are assumed transport wind turbine components to project sites. The fuel usage estimate comes from Weeks Marine. The amount of emissions potentially generated is calculated using these data and the emission factors discussed above.

No studies estimate vessel emissions produced during O&M of wind projects. Calculating these emissions would involve estimating fuel usage for smaller crafts that transport crew and equipment to the sites. We do not have access to these data. Also, as offshore bases are likely to be used to support maintenance teams servicing far-shore projects, calculating emissions becomes increasingly challenging. Thus, calculating emissions generated during O&M is beyond the scope of this study.

2.4.1.5 Selected Models

Emission factors used to estimate ship-generated emissions come from the IMO study (Buhaug et al., 2009). To calculate social costs of added emissions generated during vessel rerouting, we use estimates from Gallagher (2005), Holland and Watkiss (2002), Wang and Corbett (2007), Faber et al. (2012), Boardman et al. (2011), and the Interagency Working Group on Social Cost of Carbon (2013).

2.4.1.6 Conclusions

Past research findings are summarized as follows:

Very few studies estimate the cost of vessel rerouting or provide models that can easily be adapted to the problem at hand. The papers also have diverse approaches to estimating direct and indirect costs, or simply state that the effects of changes to traffic management systems, whether caused by rerouting or speed reduction

measures, would have minimal economic effect. Thus, no standard approach to estimating these costs exists.

Yet it is clear that for estimating direct impacts of rerouting, the cost of fuel, operating and capital costs should be considered. Some studies also estimate additional direct costs, such as costs of delays, increased multiple port calls and higher intermodal costs. Indirect impacts include economic effects from diversion of traffic to other port areas and the associated impact on income and employment. Due to time constraints, we concentrate only on estimating private shipping costs and do not evaluate the total social costs incurred due to potential delays in shipments or increase in marginal costs for shippers.

For estimating the direct costs of vessel rerouting, we rely on the available methods for calculating fuel usage, the industry-produced hourly operating costs and capital costs. As no specific annual fuel prices are available, the fuel costs are estimated assuming the cost of \$1,000/ton of MDO/MGO fuel. It is an approximation of the cost of bunker fuel across markets listed on bunkerworld.com¹³.

Numerous studies emphasize the drastic increase in cost of offshore wind energy with distance from shore and water depth. Several authors quantify this relationship and provide specific estimates such as cost per km of transmission cables or installation costs. Weight functions and costs of jackets are significantly more difficult to locate. Many studies rely on sparse industry data or proprietary information used by authors for modeling, but which is not released in the studies. Transmission

¹³ The uncertainty regarding fuel costs, especially in the light of 2015 Emission Control Area (ECA) regulations, was accounted for in the sensitivity analysis, where we assumed that fuel costs would double in the future.

cable losses and the costs of transporting components are especially limited. Additionally, many of the components are manufactured specifically for projects considering site conditions and engineering requirements. Thus, the cost estimates in our model serve as a general representation of component costs. For transmission losses and component transportation costs, we rely on data provided by our industry partners.

For research on the social cost of air emissions, we use methodologies, emission factors for specific pollutants and estimates of costs per ton of emissions from the available studies. A more complete analysis is beyond the scope of this paper.

The most applicable and comprehensive model for each research component is selected. The choice for each method is explained in detail in the next chapter.

Chapter 3

THEORETICAL FRAMEWORK AND METHODOLOGY

3.1 Spatial Data Analysis

For the first portion of the study, we use spatial data analysis tools. Spatial data analysis uses spatial references associated with each data point, specified within a certain system, and draws on data to describe spatial interactions (Haining, 2003). The analysis allows for visual representation of data and for illustrating changes introduced by the proposed alternatives.

Using ArcGIS and Quantum GIS software, we determine existing commercial vessel traffic densities and habitual travel patterns (those portions of the sea where higher densities of ships traverse as opposed to legally designated routes such as Traffic Separation Schemes (TSSs)) (Vanderlaan et al., 2009). Our methods to determine traffic densities are similar to those used to analyze a shift in vessel traffic off Massachusetts to reduce the probability of vessel strikes of right whales (Vanderlaan et al., 2009). We also identify vessels that would be rerouted and draw hypothetical Status Quo and Alternative wind energy areas (WEAs). To estimate the types of foundations used, we determine water depths within each WEA.

3.1.1 The Study Area

The study area extends to northern New Jersey, beyond the port of New York, down to southern Virginia and approximately 370 km offshore to the boundary where

Automatic Identification System (AIS) data begins tracking vessel locations. The geographic coordinates of the study area are: -76.98, 35.78; 71.98, 40.98.

3.1.2 Detailed Methods

3.1.2.1 Datasets Used

We use Automatic Identification System (AIS) dataset to model vessel traffic density. AIS is a maritime digital communication system that continuously receives and transmits vessel data over very-high frequencies (US Coast Guard, 2011a). Originally started in 2003, after the US Coast Guard implemented a vessel safety rule (Title 33 Code of Federal Regulations 164.4), AIS transponders are now required on all vessels of 65 feet or greater and transiting U.S. waters (Bates et al., 2012). AIS is programmed to transmit the vessel's call sign, name, speed, dimensions, origin and other parameters multiple times each minute. Currently, AIS is required on vessels with length of 20 meters or longer (Silber and Bettridge, 2010).

We use an annual dataset for 2009 (with a partial month of June) in this study. The data was obtained through confidentiality agreements with BOEM and NOAA. The dataset was originally downloaded in a point format and converted to track lines (polylines) linking broadcast data from unique vessel identification numbers for each month. A beta tool (AIS Data Handler for ArcMap 10) developed by National Oceanic and Atmospheric Administration (NOAA) Coastal Services Center (NOAA, 2011) was used for this.

We also use the 2009 USACE Port Entrances and Clearances dataset (USACE, 2009) that contains detailed information on all foreign vessels engaged in foreign trade in the US. It contains data on origin and destinations and on vessel types (International

Classification of Ships by Type (ICST)). It is used to select large deep-draft vessels from the AIS dataset.

3.1.2.2 Affected Vessels

We focus on economic impacts of rerouting large deep-draft vessels that participate in foreign commerce. We reclassify the ships to create five categories: container ships, tankers, general cargo ships, bulk carriers, and vehicle carriers.

We evaluate the effects of rerouting of these vessels presently traveling at approximately 53 km from shore¹⁴ on coastwise routes between New Jersey/New York port area and ports within Delaware Bay and Chesapeake Bay. We examine the costs associated with having these ships instead transit at approximately 74 km from shore within the currently established habitual traffic patterns (HTPs) already used by vessels on longer voyages. Such a scenario may be facilitated by an extension or slight shift of some TSSs, so vessels can be directed farther in the ocean before they can enter the TSSs.

We specifically avoid rerouting ships traveling within habitual traffic patterns that are located closest to the shore (approximately 10 km from the coast) and that are mostly comprised of tug and barge traffic¹⁵. This traffic is thus excluded from our analysis. Fishing vessels and passenger ships are excluded from the analysis, although, depending on size, they also may have to reroute.

¹⁴ Calculated as the average of distances from the coasts of NJ, DE, MD, and VA to the center of the estimated habitual traffic pattern, measured as a straight line.

¹⁵ An inside corridor could be created for oceangoing tugs and barges that transit the area where the affected ships currently transit.

3.1.2.3 Modeling Vessel Density

3.1.2.3.1 Selecting Vessel Trips for Analysis

The traffic densities are modeled only for container ships, tankers, general cargo ships, bulk carriers, and vehicle carriers that transit in the Mid-Atlantic. To isolate these vessel trips, we use the 2009 AIS dataset and the 2009 USACE Port Entrance and Clearance dataset. As the density analysis requires substantial processing, we exclude the records from each of the original datasets that do not have complete data needed for further analysis (see Fig. 3.1).

First, we exclude the missing records from the AIS dataset (55,310 records), which represent all vessel trips recorded with AIS in 2009. 14,833 records have missing or incomplete International Maritime Organization (IMO) numbers, which are unique digits used to identify vessels. These records are omitted, as they cannot be identified as distinct vessel trips. 40,477 records remain in the AIS dataset.

We then format the 2009 USACE Port Entrance and Clearance dataset. The dataset consists of inbound and outbound files. We create port pairs by linking these files by the IMO numbers. As several thousand records have missing IMO numbers and cannot be linked, they are omitted¹⁶. 77,573 records remain. This USACE dataset is then linked with the remaining 40,477 records from the AIS dataset. The steps are listed in Figure 3.1.

¹⁶ The inbound dataset has 84,599 records, 6,835 of which have incomplete or missing IMO numbers. The outbound dataset has 84,545 records, 7,103 of which have unknown IMO numbers.

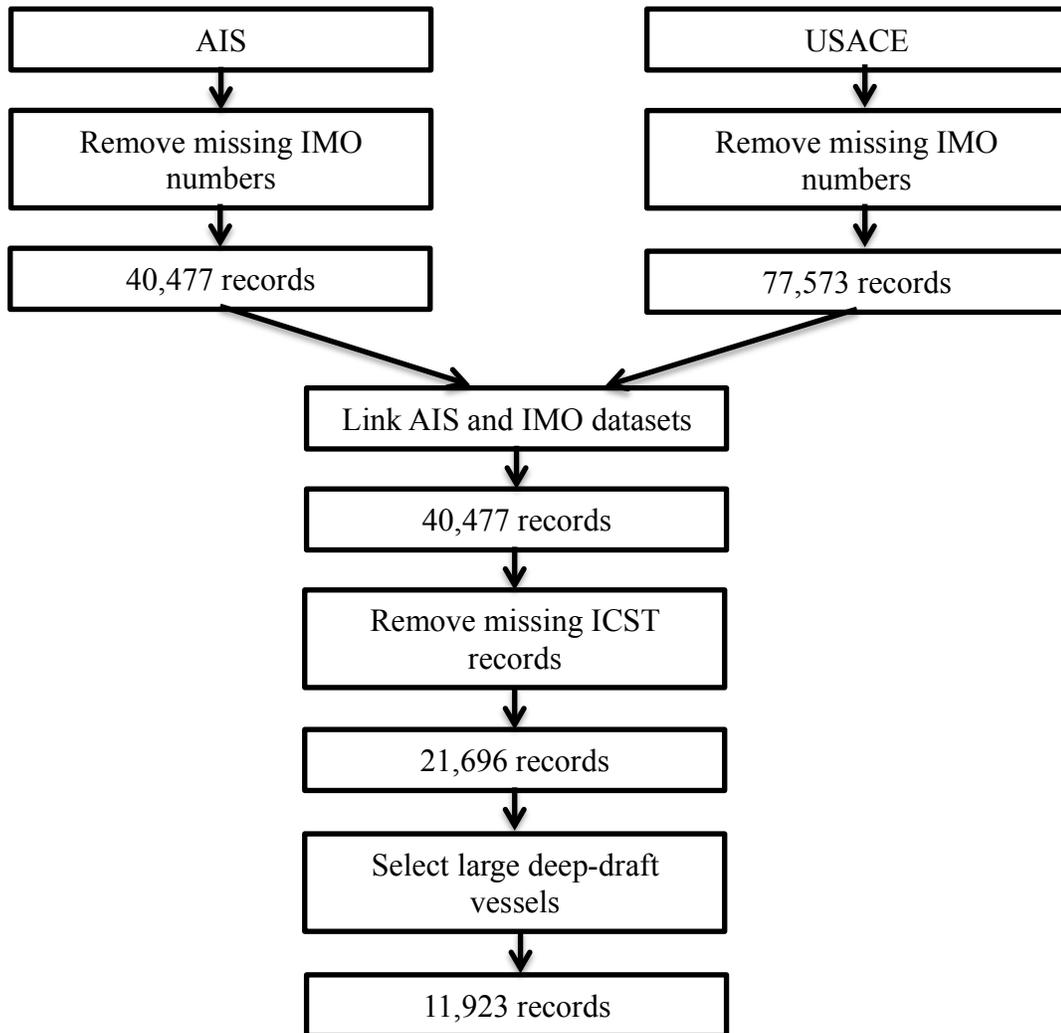


Figure 3.1: Finalizing the vessel traffic dataset for density analysis

From the resulting dataset we select vessel trips with clearly identified ICST data on vessel type. Records that do not have this data are excluded, as they cannot be used for density and economic analyses. 21,696 records remain. We assume that excluded records without IMO and ICST data are randomly distributed.

From the dataset with 21,696 records, we select vessel trips that are clearly identified as taken by container ships, tankers, general cargo ships, bulkers and vessel carriers. As a result, 11,923 records remain after USACE and AIS records are linked to create a single dataset. We use these records, as only these records contain the data needed to model traffic densities and determine habitual traffic patterns in the Mid-Atlantic.

3.1.2.3.2 Calculating Vessel Density for Each Grid Cell

To reduce processing time during density analysis, the 11,923 records are modified. Geometries are simplified to reduce the number of vertices and smooth the lines representing vessel voyages. This significantly improves performance and reduces processing time. The datasets are also clipped to the study area (-76.98, 35.78; 71.98, 40.98) and projected using Albers Equal Area Conic projection. The projection is created to improve the display of the vessel densities based on the study area location and shape.

Table 3.1: Vessel types used for estimating ship traffic densities (after the original dataset is simplified, clipped and projected)

	Number of trips in the sample	Percentage of the sample
Container ships	5,018	42.08%
Tankers (oil/chemical tankers, crude oil tankers, oil product tankers)	3,250	27.26%
Bulk carriers	1,498	12.56%
Vehicle carriers	1,274	10.69%
General cargo	883	7.41%
Total	11,923	

The relative vessel density is calculated using the datasets of trips completed by each type of vessels (Table 3.1). Several “fishnets” are created to cover the study area in segments. A fishnet is a 1 km x 1 km grid used to calculate the added length of all vessel tracks that transit a given cell. Although this method does not calculate the number of vessels transiting through a grid cell, it allows for a representation of relative vessel density. Relative densities are modeled for each ship type separately. The resulting datasets are displayed using a common range of density values (Figure 3.2).

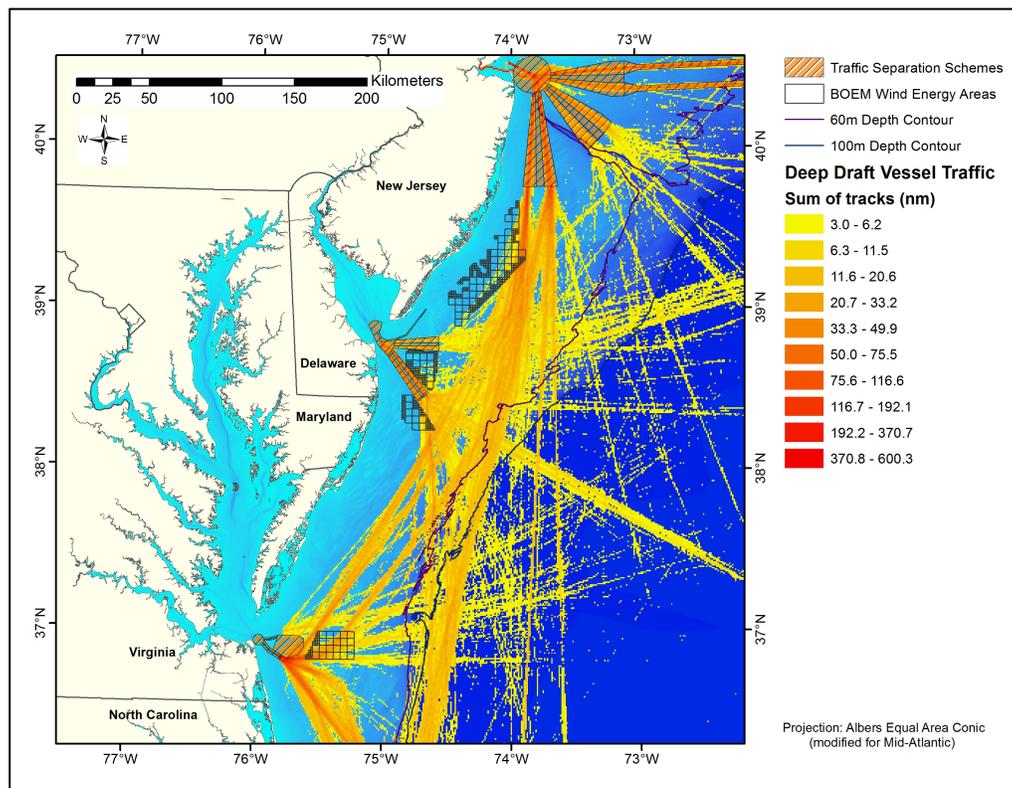


Figure 3.2: Relative density of vessel traffic in the Mid-Atlantic and existing WEAs

3.1.2.4 Determining the Total Population of Affected Vessel Trips

The total population of affected ships traveling along the route of interest between the Mid-Atlantic ports is determined based on the 2009 USACE Port Entrance and Clearance dataset. The dataset represents all vessel trips between the US ports completed by large vessels engaged in foreign trade. Using origin and destinations data (OD), we establish port pairs. The overall process is illustrated in Figure 3.3.

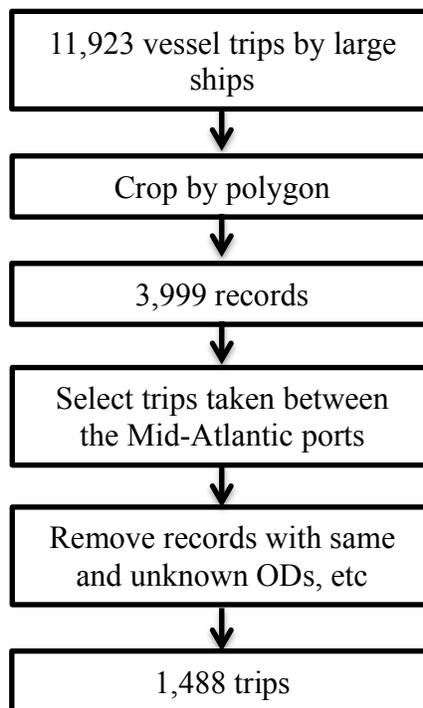


Figure 3.3: Determining the total population of vessels affected by the rerouting

To identify which specific vessel trips would be affected by the proposed rerouting scenario, we use track lines representing the 11,923 vessel trips of

containerships, tankers, general cargo ships, bulkers and vehicle carriers identified earlier. Cropping the vessel routes between NJ/NY harbor, Delaware Bay and Chesapeake Bay by a polygon captures 3,999 vessel trips (Fig. 3.4). These include voyages that not only transit between the ports of NJ/NY, Delaware Bay and Chesapeake Bay, but also those trips that originate or conclude elsewhere but transit the same waters contained within the polygon.

To isolate the affected trips that are taken between the Mid-Atlantic ports, we use the origin-destination (OD) information from the 2009 USACE dataset. We reclassify the port names with more general geographic names: NJ/New York, Delaware Bay, Chesapeake Bay, US South Atlantic, US Gulf, etc. Twenty-two percent of trips in the dataset are listed having the same origins and destination (e.g., Baltimore, MD→ Baltimore, MD). We assume that these trips represent vessel movements between different terminals within the same port. These vessels are removed from the dataset. Records with unknown or blank ODs are also removed. Additionally, trips between ports within the same bay (e.g., Port of Wilmington→Port of Philadelphia) are removed from the dataset, as the rerouting scenario would not affect these trips.

The remaining 1,488 trips represent all vessels that travelled between the ports in the Mid-Atlantic in 2009. This number of vessel trips is comparable to the 2010 and 2011 estimates of the total number of cargo and container ships transiting between the bays/harbors in the region provided to us by the US Coast Guard (personal communication). Thus, the total economic cost is calculated for 1,488 vessel trips that would be affected by the rerouting scenario.

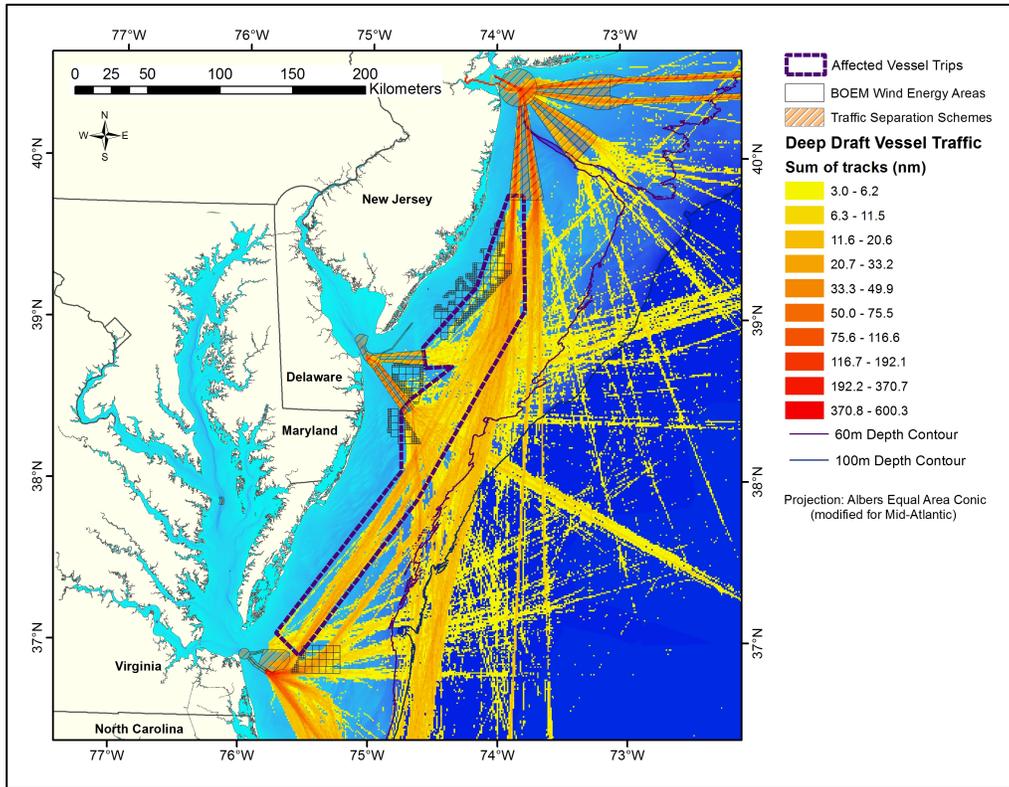


Figure 3.4: Ship traffic density and the vessel trips affected by the proposed rerouting scenario

3.1.2.5 Selecting a Sample of Affected Vessel Trips for Economic Analysis

For economic analysis, which includes calculating vessel fuel usage and cost, and operating and capital costs, we use the 2004 Lloyd’s Register of Shipping database. The database contains data on vessel characteristics, such as size, number of engines and their power. We link the Lloyd’s Register dataset with the dataset containing 3,999 records (trips with complete IMO and ICST numbers traversing the polygon in Fig. 5). 2,228 records remain. The process is illustrated in Figure 3.5.

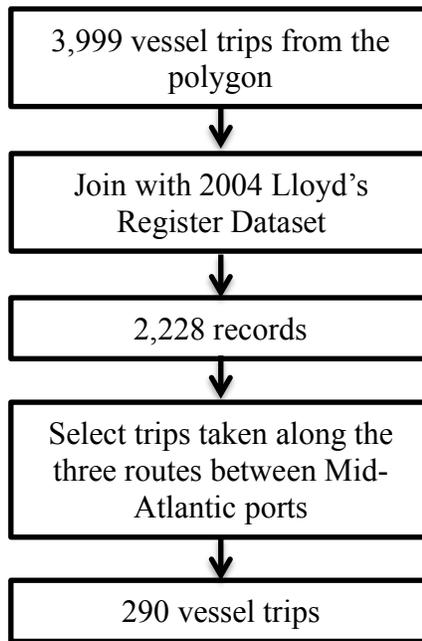


Figure 3.5. Selecting the sample of affected vessel trips for economic analysis

Table 3.2: Breakdown of vessel trips by route from the sample

Route	Number of vessel trips	Used or removed	Notes
NJ/NY and Delaware Bay	132	used	
NJ/NY and Chesapeake Bay	120	used	
Delaware Bay and Chesapeake Bay	38	used	
Mid-Atlantic ports and outside of the study region (US South Atlantic, US Gulf, etc)	687	removed	Would not pass within the affected route
Between regions outside of the study area	644	removed	Either recorded by mistake or in passing to another location

Between ports within the same bay (e.g., Norfolk, VA and Baltimore, MD)	31	removed	Will not be affected by the rerouting measures
Same origin and destination	512	removed	Likely to represent movements within the same port
Blank or unknown OD	64	removed	Not possible to establish which routes these belong to
Total	2,228		

As the alternative routing scenario would not affect all of these trips, we determine the records that represent voyages that would have to be rerouted. The trips that would not be affected by the scenario are removed from the analysis (Table 3.2). 290 vessel trips are used for economic analysis. The total economic effects are later scaled to represent the added costs for all affected 1,488 vessels attained from the USACE dataset, as is discussed above.

3.1.2.6 Measuring the Extent of Rerouting

We measure the extent of the proposed vessel rerouting separately for trips: 1) between Delaware Bay and NJ/NY harbor; 2) between NJ/NY harbor and Chesapeake Bay; and 3) between Delaware Bay and Chesapeake Bay. To measure the added voyage length, we draw the boundaries of the habitual traffic patterns (HTPs) in ArcGIS to represent the corridor along which vessels travel between the Mid-Atlantic ports (Fig. 3.6., 3.7, 3.8). These HTPs represent average voyage lengths. Even though we measure the distance for each route separately, the HTPs are drawn as single polygons for easier visualization. We draw the HTPs to/from the boundaries of traffic separation schemes (TSSs), as these are assumed to remain unchanged.

Figure 3.6 portrays the status quo HTP. Figure 3.7 shows the suggested alternative HTP. Both routes are shown on Fig. 3.8, illustrating the extent of the proposed rerouting. We measure the length of each route in the status quo and alternative scenarios (Table 3.3) and calculate the number of added kilometers. The average added length per trip is 18.5 km (10 nautical miles).

Table 3.3: Average vessel route lengths before and after rerouting

Route (between)	Length (s quo)	Length (alt)	Added length
NJ/NY and Delaware Bay	144.5 km (78 nm)	166.7 km (90 nm)	22.2 km (12 nm)
NJ/NY and Chesapeake Bay	355.6 km (192 nm)	370.4 km (200 nm)	14.8 km (8 nm)
Delaware Bay and Chesapeake Bay	203.7 km (110 nm)	222.2 km (120 nm)	18.5 km (10 nm)

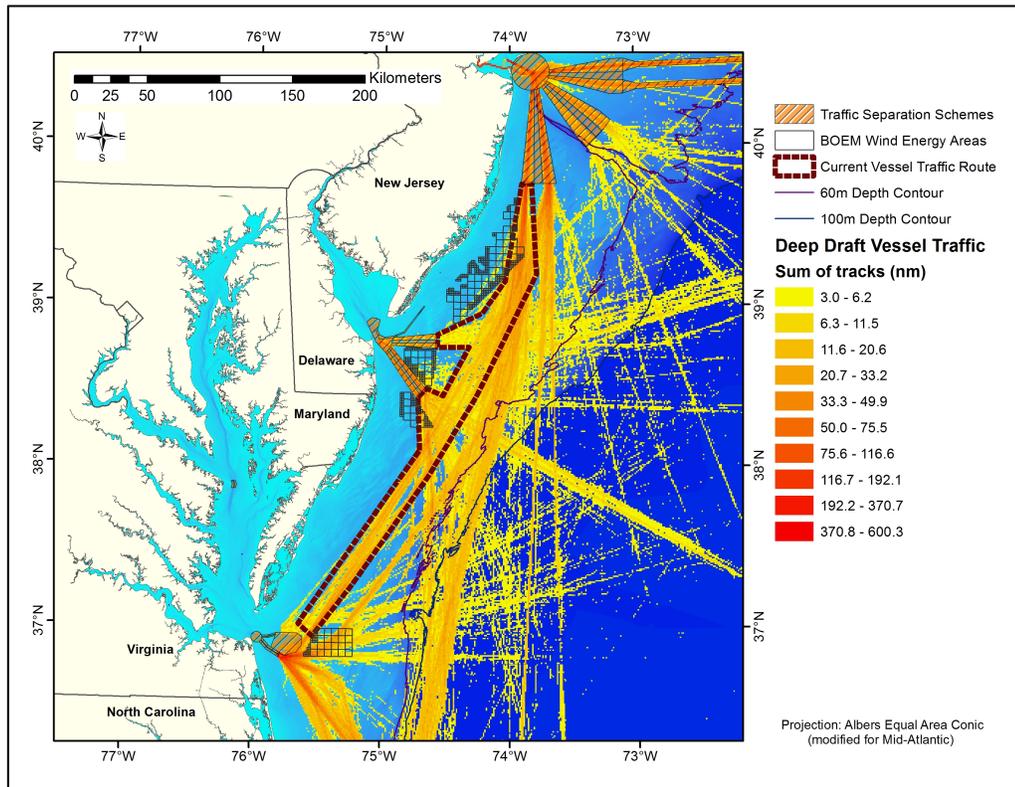


Figure 3.6: Vessel traffic density and the routes between the Mid-Atlantic ports proposed to be modified

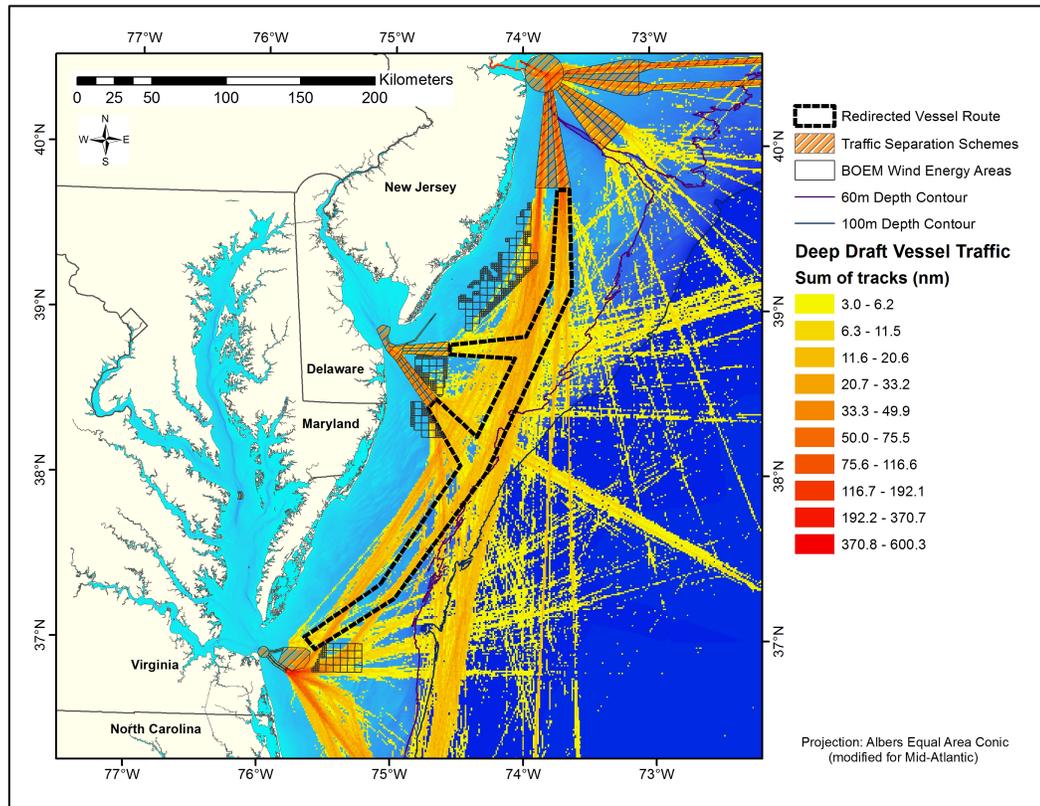


Figure 3.7: Vessel traffic density and the redirected vessel routes between the Mid-Atlantic ports (the alternative scenario)

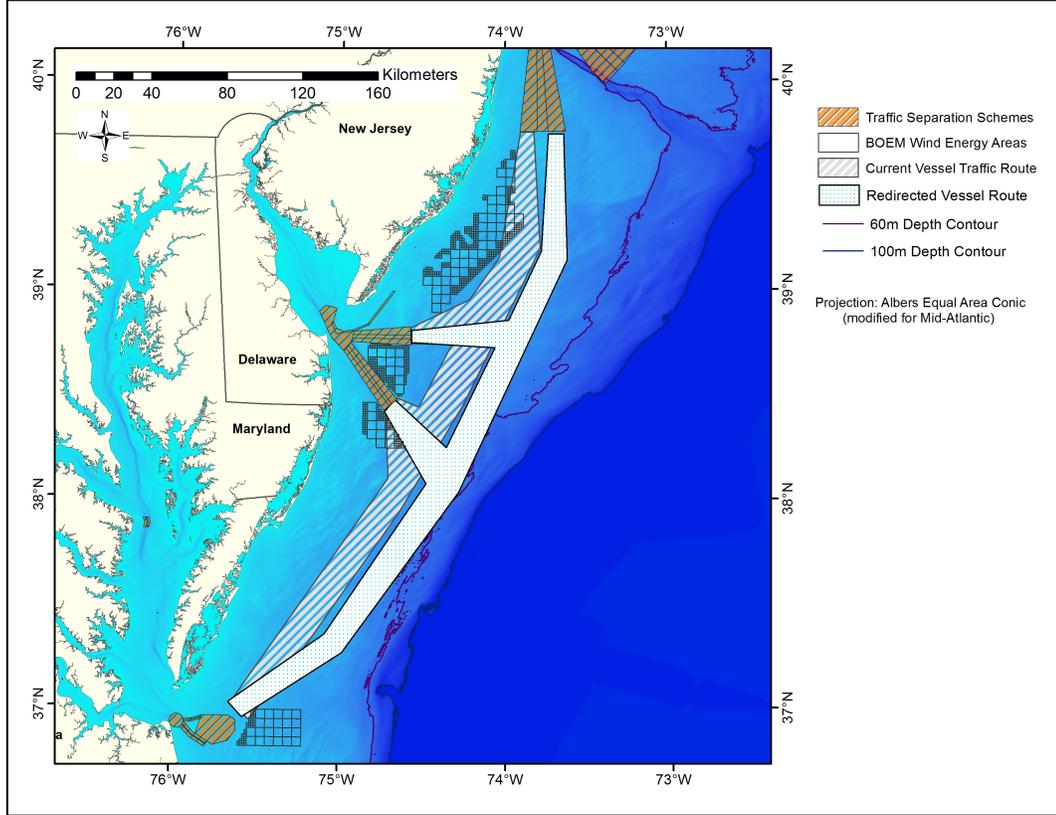


Figure 3.8: Status quo and alternative vessel routes

3.1.3 GIS Analysis of Bathymetry for Offshore Wind Energy Areas

We use ArcGIS software to draw hypothetical areas that are assumed to serve as future wind energy areas (WEAs) in the status quo and alternative scenarios. We also analyze bathymetric data to determine the foundation types in these WEAs.

3.1.3.1 Determining Hypothetical Locations of Status Quo and Alternative Wind Energy Areas (WEAs)

3.1.3.1.1 Alternative WEAs (ALT-WEAs)

The locations of Alternative WEAs (ALT-WEAs) are determined first. Within the current habitual traffic route, we draw blocks that would be open for wind development if vessels were rerouted (Figure 3.9). These Alternative Wind Energy Areas (ALT-WEAs) are drawn based on the following criteria:

- 1) ALT-WEAs lay in the areas where vessels currently transit between Chesapeake Bay and the port of New York/New Jersey.
- 2) Where feasible, ALT-WEAs are drawn directly adjacent to current WEAs proposed by Bureau of Ocean Energy Management (BOEM)¹⁷.
- 3) Furthermore, based on the assessment of wind energy development activities in the context of military operations conducted by the Department of Defense (DOD) (Engle, 2012), ALT-WEAs are adjusted to avoid areas that DOE had suggested excluding.

¹⁷ The southern portion of the traffic separation scheme leading in and out of the NY/NJ harbor could be rotated by 5 degrees to the east to ensure that there is enough separation between the TSS and the proposed ALT-WEA. Alternatively, the northern portion of the NJ ALT-WEA could be amended if such a shift of the TSS is not feasible.

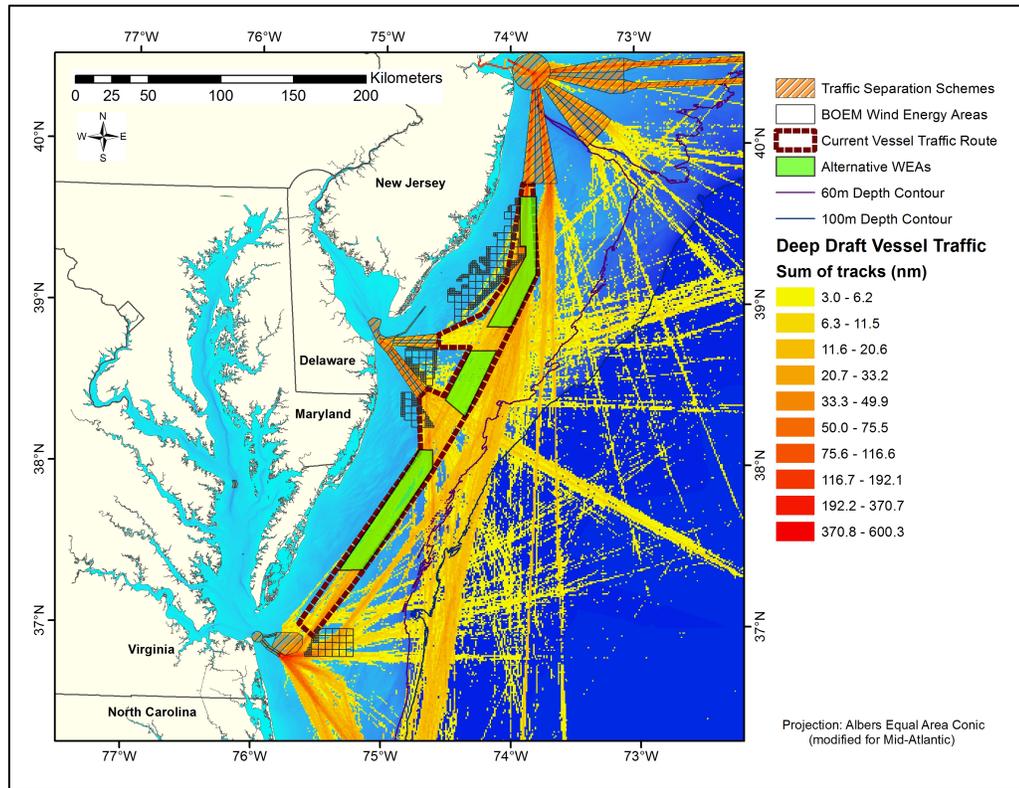


Figure 3.9: Affected current habitual vessel traffic pattern and Alternative Wind Energy Areas (ALT-WEAs) that could be open for development if the traffic are rerouted

The size of and the State the ALT-WEAs is located off are listed in the table 4 below. NJ WEA is 1,127 km²; DE – 742 km²; and MD/VA – 1,334 km².

3.1.3.1.2 Status Quo WEAs (SQ-WEAs)

If vessel traffic patterns remained unchanged, to meet the federal government’s goal of 54 GW of installed wind capacity by 2030, wind projects would be built far offshore. The SQ-WEAs represent blocks that would most likely be developed off the

states of NJ, DE, MD and VA once BOEM-designated WEAs that are located in shallow near shore areas have been developed.

The SQ-WEAs are drawn to generate an equivalent amount of power at the same point of delivery as the ALT-WEAs. This facilitates a straightforward comparison of costs and benefits. The following criteria are used to draw the SQ-WEAs:

- 1) The SQ-WEAs are located in transitional waters of more than 30 meters.
- 2) The SQ-WEAs avoid major existing habitual traffic routes. This is accomplished based on visual analysis of relative traffic densities.
- 3) SQ-WEAs are drawn off each of the Mid-Atlantic States.
- 4) Each SQ-WEA is at least 260 km². This avoids modeling very small areas.

ALT-WEAs and SQ-WEAs are shown on Figures 3.9, 3.10, and 3.11.

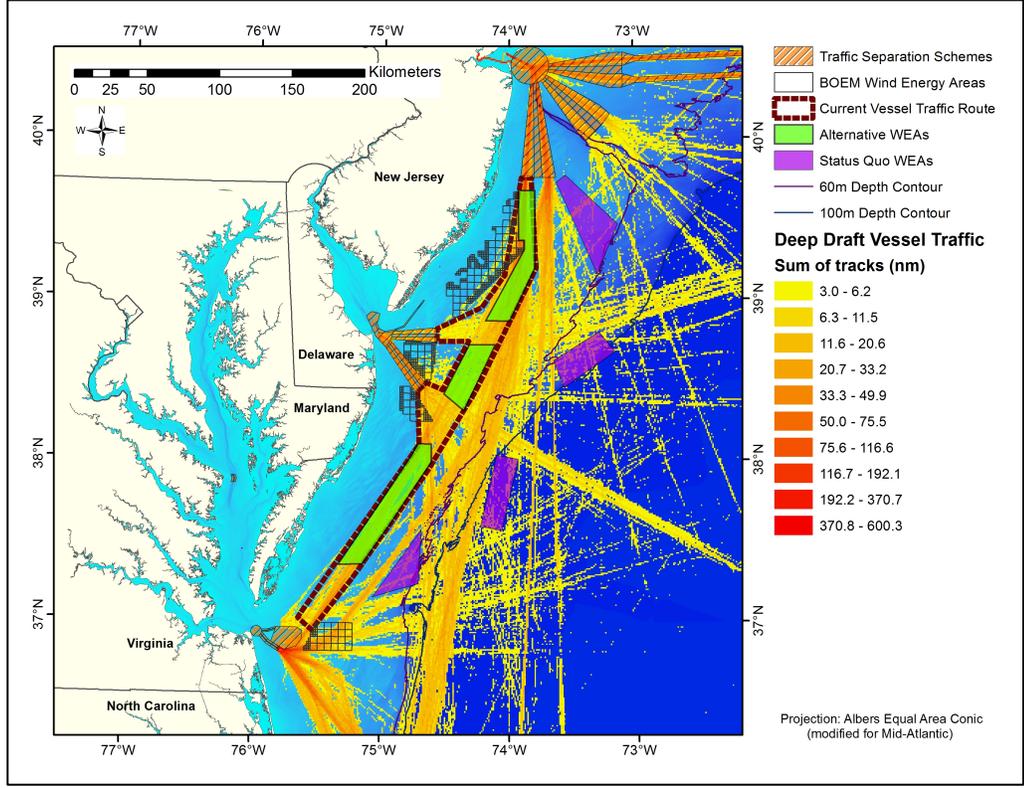


Figure 3.10: Affected current habitual traffic pattern, ALT-WEAs that could be opened to development and SQ-WEAs that would have to be developed if vessels are not rerouted

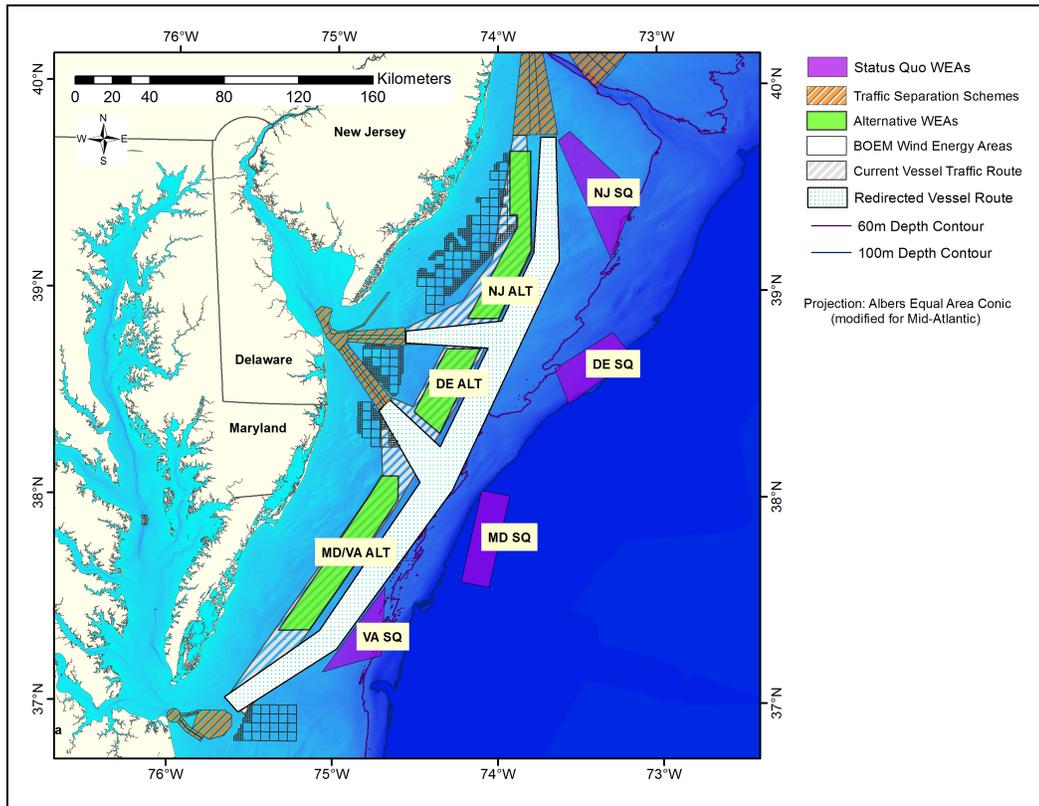


Figure 3.11: Status quo and alternative vessel routes and WEAs

3.1.3.2 Determining Bathymetry within the WEAs

To estimate the cost of turbine foundations, we determine average depths in the selected WEAs. First, we extract bathymetry contours.

To extract bathymetry contours in 10-meter increments, we use Coastal Relief Model from the NOAA/ National Geophysical Data Center (NGDC) downloaded as a digital elevation model (NOAA, 2009). The model uses public land and seafloor elevation data to depict Earth's land surface and ocean floor. The Coastal Relief Model consists mainly of the 3-arc-second (~ 90 m) elevation grids 1 degree in latitude by 1 degree in longitude. In these grids, the elevations are resolved to 1/10 of a meter.

The subsequent dataset is used to determine which foundation technology would be employed in the ALT-WEAs and SQ-WEAs. We assume that jackets will be used for water depths of up to 60 m, with floating Tension Leg Platform (TLP) foundations (vertically moored floating structures) deployed in waters deeper than 60 m. Although we considered employing monopile foundations, given that we are modeling for the larger 5 MW wind turbines in deep waters, we limit our analysis to jacket and floating foundations.

Each of the polygons representing SQ-WEAs and ALT-WEAs are intersected with bathymetry contours datasets. Several datasets are created. This allows us to calculate the size of each area with the particular water depth range (10-19.9 m; 20-29.9 m; 30-39.9 etc). To simplify the display of these percentages, we list each WEA by only its primary foundation technology in the status quo and alternative scenarios in the Table 3.4 below.

Table 3.4: Primary foundation technology and percentage of area for SQ and ALT-WEAs

	Status Quo	Alternative
WEA	(Primary foundation technology) by % of area	(Primary foundation technology) by % of area
NJ	Jackets (98.22%)	Jackets (100%)
DE	Floating (100%)	Jackets (100%)
MD	Floating (100%)	
VA	Jackets (95.23%)	Jackets (100%)*

*MD and VA combined

These estimates with specific water depth ranges are used in the economic model. We determine the number and weight of jackets and floating structures built to house wind turbines at particular water depths.

3.1.4 Cost-Benefit Analysis (CBA)

3.1.4.1 CBA as a Framework

For the second portion of this study, we used cost-benefit analysis (CBA) framework to determine whether there would be net social benefits from rerouting coast-wise deep-draft vessel traffic farther offshore to open near-shore areas for offshore wind development. CBA is an established method frequently used to inform policy decisions and is used to provide insight into whether a particular proposed policy or project would be in the public interest or to choose among alternatives (Zerbe and Bellas, 2006). After all categories of costs and benefits are identified, the impacts are monetized (dollar values are attached to them) (Boardman et al., 2011). Then, costs and benefits are brought into a single year to ensure that monetary values do not vary between the categories. Next, costs and benefits are discounted to obtain

present values. The present value of each alternative is then compared to determine which produces higher net benefits (ibid). That project or policy is considered worthwhile.

3.1.4.1.1 Examples of Cost-Benefit Analysis Studies

Cost-benefit analysis is a widely used technique for evaluating policy decisions regarding transportation. CBA has been used for evaluating multiple projects in the US: e.g., harbor deepening for the Savannah Expansion Project, construction of Seattle Monorail, extension of the Rock County Airport Runway, expansion of the Commercial Vehicle Information Systems and Networks (CVISN) Program, construction of truck bypass in California and others (Transportation Cost-Benefit Analysis, 2012). The US Army Corps of Engineers, the federal agency that has general responsibility for investigating, managing and developing the nation's water and water-related environmental resources, conducts CBAs for all of its projects. In 2009, the Army Corps introduced a guide on principles for conducting CBA to evaluate federal water projects¹⁸.

CBA is also performed in the context of policies and services affecting vessel traffic and U.S. ports. For example, in 1991, US Department of Transportation (US DOT) performed a study evaluating costs and benefits of USCG establishing potential Vessel Traffic Services (VTS) in certain US deep draft ports in the Gulf and on the

¹⁸ Principles and Guidelines for Evaluating Federal Water Projects: the U.S. Army Corps of Engineers Planning and the Use of Benefit Cost Analysis. Available from: http://evans.uw.edu/sites/default/files/files/Principles_and_Guidelines_for_Federal_Water_Projects_0.pdf

Atlantic and Pacific coasts (Malo et al., 1991). The study forecasted vessel casualties, avoided losses, vessel design costs etc.

The CBA framework is useful here as clear direct and indirect costs and benefits have been identified and can be monetized given the currently available methodologies. Also, the results of our study can inform the decision-making process regarding the potential modifications to vessel routing schemes that are currently evaluated by the U.S. Coast Guard.

3.1.4.2 Valuing Direct and Indirect Costs and Benefits

Direct costs incurred by vessel operators include fuel, operating and capital costs. Direct benefits are calculated in the form of cost savings that could be attained if offshore wind projects are developed in shallower waters closer to shore instead of at deeper far-shore sites. Lower offshore wind costs would likely lead to cheaper wind-generated electricity made available to the Mid-Atlantic residents.

Capital expenditures (CAPEX) and operating and maintenance (O&M) costs are valued here as direct benefits. The CAPEX include: foundation costs, transmission cable costs, transmission cable installation costs, and wind turbine and foundation transportation costs. Operating and maintenance expenditures include scheduled maintenance costs incurred during the 25-year lifetime of each turbine. Other expenditures related to developing wind projects such as development fees, cost of geological and geotechnical surveys, turbine and foundation installation costs and others are beyond the scope of this analysis. However, past studies emphasize that the difficulty of development and construction far from shore raises the overall cost of projects.

Indirect costs and benefits focus on the social cost of air pollutants: SO₂, NO_x, PM, and CO₂. The costs represent the value of social damages of emissions generated during vessel rerouting. The benefits represent the value of reduced damages from lower emissions generated by vessels transporting components to wind project sites closer to shore.

3.1.4.3 Costs and Benefits Components that Are Not Monetized

Some costs and benefits are not monetized due to data limitations. Thus, vessel emissions generated during O&M are not monetized, as we do not have data on O&M vessel characteristics needed to calculate emissions. The costs of offshore wind electrical substations and turbine and foundation installation cost are not estimated due to the lack of data. Estimating the cost of potential vessel delays and vessel operators deciding not to call on the Mid-Atlantic ports because of the added length of transits are outside of the scope of our analysis.

3.1.5 Modeling Direct Costs to Commercial Shippers before and after Rerouting

Our modeling of direct costs to commercial shippers before and after rerouting relies on several assumptions. First, we assume that vessel operators have perfect information about the location of the wind projects and have enough time to reroute. They can plan their voyage with appropriate deviation from the original route. Second, we assume that all vessels would continue transits despite the marginal increase in the cost of transit due to rerouting. Third, vessels that travel from one of the Mid-Atlantic ports to the destinations outside of the study area are likely to be affected only minimally. Thus, the effects on their costs are not estimated.

3.1.5.1 Modeling Fuel Costs

We calculate per-trip fuel use of each ship by adding fuel used by main and auxiliary engines. For the main engine, the fuel consumption per trip follows the cubic law of design speed and operating speed (Corbett et al., 2009). The auxiliary engine consumption is added to that of the main engine. The per-trip fuel use formula is provided below:

$$F_{ijk} = [MFk \times (s_{1k}/s_{0k})^3 + AFk] \times (d_{ij} / 24s_{1k}) \quad (\text{Eq. 1})$$

Where,

i - origin port

j - destination port

k - individual vessel on the route

F_{ijk} - fuel consumption per trip

MFk - main engine(s) daily fuel consumption, tons/day

s_{1k} - operating speed, nm per hour

s_{0k} - design speed, nm per hour

AFk - auxiliary engine(s) daily fuel consumption, tons/day

d_{ij} - distance between two ports (nm)

Based on the specifics of our rerouting scenario, we use the following inputs to calculate fuel usage:

- 1) Daily engine fuel consumption (*MFk*) and auxiliary engine fuel consumption (*AFk*) are determined by the fuel consumption rates (g/kWh), power of the vessel, and engine load factors (Corbett et al., 2009). The daily main engine consumption rate is 206 g/kWh (Wang et al., 2007); for the auxiliary engine, the daily consumption rate is 221 g/kWh (Corbett et al., 2009). The average main engine load factor is 0.8 and the average auxiliary engine load factor is

0.5 (Corbett et al., 2009; Wang et al., 2007). Based on these data, MFk and AFk are calculated as:

$$MFk = \text{Main engine power (kW)} \times \text{daily fuel consumption rate (g/kWh)} \times 24/10^6 \quad (\text{Eq. 2})$$

$$AFk = \text{Aux engine power (kW)} \times \text{daily fuel consumption rate (g/kWh)} \times 24/10^6 \quad (\text{Eq. 3})$$

- 2) The average lengths of status quo trips between the ports of interest and the length of alternative trips are used as the ‘*distance between two ports*’ input (Table 3.5). The fuel use here only accounts for at-sea steaming usage; it does not include fuel used during maneuvering in and out of port because these would not change as a result of rerouting.

Table 3.5: Average vessel route lengths before and after rerouting (in km and nautical miles (nm))

Route (between)	Length (s quo)	Length (alt)	Added length
NJ/NY and Delaware Bay	144.5 km (78 nm)	166.7 km (90 nm)	22.2 km (12 nm)
NJ/NY and Chesapeake Bay	355.6 km (192 nm)	370.4 km (200 nm)	14.8 km (8 nm)
Delaware Bay and Chesapeake Bay	203.7 km (110 nm)	222.2 km (120 nm)	18.5 km (10 nm)

3) Vessel operating speeds and design speeds from an assortment of sources are shown in Table 3.6 below. We use average operating speeds as representation of speeds at which vessels are operating between the Mid-Atlantic ports (Corbett et al., 2006). Design speed is based on a calculated prediction of top speed. Design speed is a representative potential operating speed, which is determined by the design and the correlation of the physical features of the vessel operating environment. It is a nearly consistent maximum or near maximum speed that could be maintained by a vessel in good weather (adapted from Fitzpatrick et al., 2003).

Table 3.6: Average operating speed and design speed by ship type

Ship type	Average operating speed, (knots)	Design speed, (knots)
Container ship	19.9	22 [^]
Tanker	13.2	16 ⁺
General Cargo	12.3	16 [~]
Bulk Carrier	14.1	15 [*]
Vehicle Carrier	16.9	18.5 ^{**}

[^]Speeds between 20 and 23.7 knots (Corbett et al. (2009); we assume 22 knots

⁺Speeds between 10 and 18 knots, with 16 knots for large crude tankers; we assume 16 knots (Shippedia, 2013)

[~]Speed between 13.4 and 18.6 knots (NMFS, 2008); we assume 16 knots

^{*}Speed is higher than or equal to 14.5 knots (except for small and Handysize bulkers) (MAN Diesel and Turbo, 2007); we assume 15 knots

^{**}Speeds between 17 and 20 knots (Deltamarin, 2011); we assume 18.5 knots

4) Main and auxiliary engine power are derived from the 2004 Lloyds Register of Shipping database (where data are available). For records with no data, average engine power across the vessels of the same type is used. As data on the size of auxiliary engines are especially sparse, adjustments have to be made for a significant portion of vessels in the dataset. Average engine power by vessel type is listed in the Table 3.7 below.

Table 3.7: Average main engine power by vessel type (based on the sample)

Vessel Type	Average Main Engine Power	Average Auxiliary Engine Power
Bulk Carrier	7,870	9,006
Container Ship	31,672	24,533
General Cargo	6,443	7,284
Tanker	12,309	10,295
Vehicle Carrier	14,570	9,749

Source: Lloyds Register (2004)

5) After the amount of fuel used per each trip is calculated, we sum the amounts used across all of the trips in the sample to estimate the total fuel used during the voyages in the sample.

3.1.5.1.1 Assumptions Regarding Fuel Used

Since August 1, 2012, stricter control of emissions of NO_x, SO_x and particulate matter for ships has been in effect within the North American Emissions Control Area (ECA), a 370-km zone off the coast of US and Canada. The ECA was created under the International Convention for the Prevention of Pollution from Ships

(MARPOL) (IMO, 2012). Within the ECA, the fuel oil used by vessels has to have no more than 1% sulfur content. On January 1, 2015, the sulfur content is expected to fall to 0.1% (IMO, 2012).

Due to these newly implemented regulations, we assume that vessels would be using Marine Diesel Oil (MDO) or Marine Gas Oil (MGO) for transit within the North American ECA and consequently within our study area. MDO (distillate oil with traces of residual oil) and MGO (100% distillate oil) - have lower sulfur content, but are more expensive than other fuels, as they require additional processing to reduce residual content (Betz et al., 2011).

To estimate the added costs that would be incurred from vessel rerouting, we use cost per metric ton of MDO/MGO. This cost is estimated based on the Eq. 4.

$$\text{Added fuel cost} = \text{Added fuel used (metric tons)} \times \$1000/\text{ton of MDO or MGO}$$

(Eq. 4)

We use publically available costs per metric ton of MDO/MGO. In November 2012, the average MDO price in Houston was \$1,028.50 per metric ton (Marcon International, Inc, 2012). The average price of MGO in Rotterdam was \$924; \$1,000 in Houston; \$1,015.50 in Fujairah; and \$934 in Singapore. These are slightly lower than the average prices in October 2012 (ibid). On January 2, 2013, bunker fuel prices ranged from \$919/ton of MDO in Singapore to \$1,082/ton of MGO in Los Angeles (Bunkerworld, 2013).

Considering such price variability and uncertainty over which affected ships are serviced on which fuel markets, we use a unit price of \$1,000 per metric ton in our model.

As our proposed rerouting measures would not come into effect until 2020 when fuel prices could be dramatically higher, we perform a sensitivity analysis to account for this uncertainty.

3.1.5.2 Modeling Operating Costs

To model the added operating costs, we use the annual and daily operating costs for vessels of different types and sizes¹⁹ (Wilkinson et al., 2011). The operating costs include: crew wages and medical expenses, provisions, lubricating oils and stores, spares, maintenance and repair, insurance, registration costs, management fees, sundries and administration total. The data is based on information received from 2,600 vessels. Using these daily costs, hourly costs are calculated by dividing the daily estimate by 24 hours.

$$\text{Hourly operating cost} = \text{daily operating cost}/24 \text{ hours} \quad (\text{Eq. 5})$$

¹⁹ These are financial or accounting costs and are not economic resource cost used by the Army Corps in their analyses of navigation operation. Financial costs are more of a snapshot in time. They reflect the rates shippers charge for moving cargo, but are often based on market conditions and can be very volatile or skewed by the level of competition or by other external factors (Knight and Mathis, 2010). The Army Corps considers economic resource costs, based on fixed and operating costs derived from analysis of the shipping industry, to be a more accurate measure (ibid). Unfortunately, given confidentiality agreements, the Army Corps was unable to make this data available to us.

To calculate the added time that would be required for vessels to make the trip between the ports of interest (between NJ/NY harbor, Delaware Bay and Chesapeake Bay), we use vessel operating speed by ship type and the distance between these destinations with and without vessel rerouting. These inputs are listed in Tables 3.7 and 3.8 above. The calculated added amount of time needed to transit along the alternative route farther from shore is then multiplied by the vessel hourly operating cost.

$$\text{Added travel time} = \text{distance between ports/vessel operating speed}$$

(Eq. 6)

Finally, to calculate the added operating cost, we multiply the added travel time per voyage in the sample by the operating cost per hour and sum all of the individual estimates.

$$\text{Added operating cost (per voyage)} = \text{added time (hours)} \times \text{hourly operating cost}$$

(Eq. 7)

3.1.5.3 Modeling Capital Costs

Capital cost for a ship is converted into a series of equal annual payments, similarly to a mortgage or a car payment (Knight and Mathis, 2010). The cost of existing and newly built ships vary significantly from year to year depending on market conditions and on vessel availability in the second-hand market (Stopford, 2011). If the ship was purchased with a loan, it is paid off with periodic payments over a certain period of time, which varies for different vessel types and depends on

conditions of specific financing arrangements. We assume that the ships in the sample are all new builds, as the average new vessel costs are the only ones available to us (UNCTAD, 2011) (Table 3.8). To determine the capital costs that would accrue to vessel owners during the hours added from rerouting we annualize capital costs over 15 years²⁰ using an interest rate of 6%²¹. The monthly payment that the owner of each vessel in the sample would make is calculated based on Eq. 8.

$$\text{Monthly payment} = \text{PMT}(\text{Annual interest rate}/12 \text{ month}) \times (\text{months}) \times (\text{vessel capital cost (present value)}) \text{ (Eq. 8)}$$

Table 3.8: Average price for new vessels

Vessel Type	Average price (2010)	Average price (2012\$, rounded)*
Oil tanker, 50,000 DWT	\$36,000,000	\$38,000,000
Oil tanker, 160,000 DWT	\$66,000,000	\$69,000,000
Dry bulk, 30,000 DWT	\$25,000,000	\$26,000,000
Dry bulk, 75,000 DWT	\$35,000,000	\$37,000,000
Container, gearless, 6,500 TEUs	\$75,000,000	\$79,000,000

Source: UNCTAD (2011)

²⁰ Based on the average pay-off period for large vessels

²¹ The interest rate was based on the vessel loan interest rate indicates on the Government of Canada (<http://www.gov.ns.ca/fish/fishlb/vessel.shtml>)

The resulting amount is then used to estimate hourly cost (Eq. 9):

$$\text{Hourly capital cost} = (\text{monthly payment} \times 12 \text{ month}) / 8,760 \text{ hours} \quad (\text{Eq. 9})$$

Based on the added time per trip estimated above, we calculate added capital cost per trip (Eq. 10). The added capital costs are then summed.

$$\text{Added capital cost (per voyage)} = \text{added time (hours)} \times \text{hourly capital cost (Eq. 10)}$$

3.1.5.4 Calculating the Total Added Vessel Cost

Using the sample representing the affected vessel trips, the added cost is calculated for:

- 132 voyages between NJ/NY and the Delaware Bay;
- 120 trips between NJ/NY and the Chesapeake Bay; and
- 38 trips between the Delaware Bay and Chesapeake Bay.

3.1.5.5 Extrapolating the Cost to All Affected Vessels

The total economic effects are extrapolated to represent the added costs for all affected 1,488 vessels attained from the USACE dataset. We use the estimated annual added costs from the sample of 290 ship trips.

The sample of 290 vessel trips is made up of tankers (39%), container ships (34%), vehicle carriers (11%), general cargo (9%), and bulk carriers (7%). However, the overall population of the affected ships (1,488) consists of tankers (9%), container ships (72%), vehicle carriers (12%), general cargo (3%), and bulk carriers (4%). To

calculate the total annual cost for the entire population, we weigh the added cost for each vessel type in the sample by the number ships of each type in the overall population (Eq. 11). Weighed cost per vessel type in the sample is then multiplied by the factor of 5.13 to adjust to the cost for the total population of 1,488 vessel records.

$$\text{Weighed cost per vessel type } (i) \text{ in the sample} = \sum \text{ of vessel cost of vessel type } i \times (\text{pop percent } i / \text{sample percent } i) \times \text{number of ships of type } i \quad (\text{Eq. 11})$$

3.1.6 Modeling Cost of Offshore Wind Projects before and after Rerouting

We make several assumptions. First, because we are ultimately concerned with the amount of power produced, we design the SQ and ALT WEAs to deliver an equivalent amount of power to the grid.²² As wind speeds and therefore capacity factors are lower closer to shore, more wind turbines would be required in the ALT-WEAs to generate the same amount of power as in the SQ WEAs. Thus, we assume that fewer turbines would be built in the SQ-WEAs compared to the ALT-WEAs. Consequently, fewer foundations, transmission cables and transportation vessels would be used as well.

Second, jacket foundations would be used for wind projects built in waters between 30 and 60-meters deep. In waters deeper than 60 meters, floating Tension Leg Platform (TLP) structures would be used. Third, HVAC transmission cables

²² Because we are using 5 MW wind turbines, and the capacity factors and transmission losses vary between the two areas, there are some rounding errors between the two areas. Otherwise, they generate an equivalent amount of power.

would be used for projects located less than 80 km from an onshore area near a substation or an offshore backbone connection. Farther from shore, HVDC cables would be used. Fourth, the transmission cables would be laid radially from the center of each WEA to the corresponding onshore substation. In the case of New Jersey, the cable would connect to the offshore transmission cable - the proposed New Jersey Energy Link (NJEL) (formerly part of the larger Atlantic Wind Connection).

Fifth, annual power outputs from WEAs are produced using capacity factors of 5 MW REpower turbines spaced 8 x 8 rotor diameters from adjacent turbines. Sixth, all turbines and jacket foundations would be transported to the site using jack-up service vessels (ex. barges) towed by tugs. Turbines placed on floating foundations would be transported by two tugs without barges.

3.1.6.1 Estimating the Number of Turbines in Each Alternative Wind Energy Area

Before specific cost calculations are performed, we estimate the number of turbines that would be housed in each WEA. To estimate the number of 5 MW turbines required in the SQ-WEAs, we first determine the number of turbines that could be located given the size of the ALT-WEAs. We then estimate the annual power in each ALT-WEA that would be delivered to shore after accounting for ALT-WEA gross capacity factors, turbine availability, wake effects, and transmission losses. Using that power generation estimate and gross capacity factors, turbine availability, wake effects²³ and transmission losses associated with the SQ-WEAs, we calculate the nameplate capacity in these WEAs.

²³ As we discuss below, turbine availability and wake effects are assumed to be the same in both the status quo and alternative WEAs.

3.1.6.2 Estimating Wind Turbine Spacing and Nameplate Capacity

Within each ALT-WEA, we calculate the footprint for each turbine (Sheridan et al., 2011) (Eq. 12). The rotor diameter for the modeled 5 MW turbine is 126 meters. As our study area has predominantly northwesterly winds during the winter and winds from the southwest in the summer, no directional pattern is chosen for the turbine spacing. We use a uniform spacing of 8 rotor diameters by 8 rotor diameters²⁴. We calculate array spacing of 1.1016 km² (Eq. 12).

$$\text{Array spacing} = (\text{rotor diameter})^2 \times \text{downwind spacing factor} \times \text{crosswind spacing factor} \quad (\text{Eq. 12})$$

The number of turbines in each ALT-WEA (Eq. 13):

$$\text{Number of turbines} = \text{Area of WEA/array spacing} \quad (\text{Eq. 13})$$

The total nameplate capacity in each ALT-WEA (Eq. 14):

$$\text{Nameplate capacity} = \text{number of turbines} \times 5 \text{ MW} \quad (\text{Eq. 14})$$

We use the estimated number of turbines and the nameplate capacity in the ALT-WEAs to calculate the number of turbines needed in the SQ-WEAs to generate the comparable power output. This process is described below.

²⁴ Jacquemin et al. (2011) suggest using spacing of no less than 7.8 diameters x 7.8 diameters.

3.1.6.3 Modeling Transmission Cable Losses for HVAC and HVDC Cable Options

First, we estimate the number of MW lost from each alternative WEAs. For wind projects built closer to shore, transmission cable losses are significantly lower. Cable losses are calculated based on the losses per km provided by the Atlantic Wind Connection for HVAC and HVDC cables. The data used are listed in the Table 3.9 below. Specific power losses are estimated as follows.

To determine the number of cables needed for each WEA, the total MW capacity in the WEA is divided by the corresponding transmission cable capacity (250 MW for HVAC or 500 MW for HVDC). Then the losses (in MW/km) are multiplied by the average distance to substation or to the NJEL, as appropriate (Eq. 15). This generates an estimate of average losses from each ALT-WEA²⁵.

$$\text{Total losses (MW)} = \text{loss per km} \times \text{total average total distance for all cables}$$

(Eq. 15)

Table 3.9: Losses of MW/km based on two cable options; the losses are optimized for a 320 kV 1,000 MW cable.

Cable type	Losses in MW/km	
320 kV dc cable, 500 MW	0.0094	based on 2400 mm ² conductor
230 kV ac cable, 250 MW	0.0718	based on 800 mm ² conductor (4 circuits for 1000 MW)

Source: Atlantic Wind Connection (2012)

²⁵ Later a similar process is used to calculate transmission losses from the SQ-WEAs.

The number of MW lost at each ALT-WEA is subtracted from the each area's nameplate capacity. Using these estimates, we calculate the average power output for each ALT-WEA. Average power output – MWa – is an estimate of how much power wind turbines would actually be delivering to the grid. This calculation combines the capacity factor, wind turbine availability losses and the wake effect losses.

As the focus of our analysis is to understand the effects of vessel rerouting, we do not conduct extensive modeling of the wind power output in the area. Instead we use available capacity factors for a 5 MW turbine estimated for our area (Dvorak et al., 2012). Capacity factor (CF) is “the actual amount of energy generated by a wind turbine during a year compared to the amount of energy that could be generated if the turbine operated at nameplate capacity during the entire year (ibid) (Table 3.10). We use CF_{gross} estimate, which is “the raw energy at the turbine without any losses” (Dvorak et al., 2012, p. 9). The CF_{gross} are summarized in the table 13 (Dvorak et al., 2012). We also assume 10% wake effect losses (Sheridan et al., 2011; Dvorak et al., 2012) and 95% wind turbine availability²⁶ (Sheridan et al., 2011). Thus, the average power output – MWa – is estimated using Eq. 16.

$$\text{MWa} = \text{MW} \times \text{Capacity Factor} \times (1 - \text{Wake Effects}) \times \text{Wind Turbine Availability (Eq. 16)}$$

²⁶ Other studies assumed availability ranging from 91% (Awarde et al., 2011), 94% (Dvorak et al., 2012) and 97% (Levitt et al., 2011), who suggest that in the future offshore wind projects will reach the availability level of land-based wind.

Table 3.10. Approximated Capacity Factors (CF_{gross}) for SQ and ALT-WEAs (for a 5 MW turbine)

WEA	SQ	ALT
New Jersey	45%	42%
Delaware	45%	42%
Maryland	42%	
Virginia	42%	40% *

*MD and VA combined

Source: Dvorak et al. (2012)

Then we estimate total energy production from the ALT-WEAs (Eq. 17). This yields output in MWh per year.

$$\text{Total Annual Energy Production} = \text{MWa} \times 8760 \text{ h/year (Eq. 17)}$$

The estimated power output in MWh for each WEA without transmission losses is converted to kWh (by multiplying by 1,000) and multiplied by 25 to estimate the total potential power production for 25 years of project operation. This represents energy production from each ALT-WEA considering the transmission losses that would occur at different distances from shore.

3.1.6.4 Estimating the Number of Turbines in the Status Quo WEAs

Using the estimated power output from the ALT-WEAs, we calculate how many turbines would be able to generate a comparable amount of power in the SQ-WEAs. As higher wind speeds would facilitate increased energy production farther from shore, fewer turbines would be needed to generate the same amount of power as would come from the ALT-WEAs. We calculate the nameplate capacity and the

number of turbines needed in the SQ-WEAs using the MWh that would be delivered to the grid from ALT-WEAs and the capacity factors from the SQ areas. We keep the wake effects losses and array availability constant. We also adjust the final nameplate capacity of the SQ-WEAs considering this difference in MW lost during transmission to shore. This was calculated using the Eq. 18 below, where a = array availability; b = wake effect losses; c = CF in SQ area; l = transmission losses.

$$\text{Pre-transmission loss MW in SQ} = \left(\frac{\text{A-WEA MWhs}}{(a*(1-b)*c*8760 \text{ hours}*25 \text{ years})} \right) + (\text{SQ}l - \text{Alt}l) \quad (\text{Eq. 18})$$

Due to rounding errors, the power output generated from the ALT-WEAs and SQ-WEAs matched by 99.89% in New Jersey; by 99.99% in Delaware, and by 99.94% in Maryland and Virginia²⁷.

To estimate the number of turbines within each SQ-WEA, we divide the estimated nameplate capacity within SQ-WEAs by turbine nameplate capacity of 5 MW. These estimates are used in the economic model.

3.1.6.5 Modeling Foundation Weight and Cost

Earlier we determined how many jacket and floating foundations would be used in each depth range within the ALT- and SQ WEAs. The weights and costs of these structures are estimated as follows.

²⁷ The difference in generation can also be attributed to rounding errors in transmissions losses, which are tied to 250 MW capacity cables.

3.1.6.5.1 Jackets

Foundation weight is estimated using available weight estimates for a jacket used to support a generic 5 MW turbine (Jacquemin et al., 2011). The cost of each jacket is estimated based on its weight and the fabrication cost per metric ton of steel, which ranges between \$5,500 – 7,000 per metric ton (Elkinton et al., 2012). We use the average of \$6,250/metric ton (in 2012\$). The total cost for each jacket is calculated according to Eq. 19. The cost estimates for all jackets are added to determine a total for each wind energy area.

$$\text{Cost of a jacket} = \text{jacket weight} \times \$6,250/\text{ton} \quad (\text{Eq. 19})$$

As a result, jackets at an average depth of 35 meters weigh 495 metric tons amounting to approximately \$3.1 million. Jackets at 45 meters, weigh 625 metric tons, amounting to \$3.9 million. And jackets at 55 meters, weigh 790 metric tons, costing \$4.9 million.

3.1.6.5.2 Floating Foundation (Tension Leg Platform - TLP)

The floating foundation consists of the tension-leg platform, three mooring lines and three anchors (Jacquemin et al., 2011). Different steel rates and anchor costs are summarized in Table 3.11. The cost per foundation is calculated based on Eq. 20, where TLP_w = weight of TLP; TLP_c = cost per ton of TLP steel; ML_w = mooring lines weight; ML_c = mooring.

$$\text{Cost of TLP} = (\text{TLP}_w * \text{TLP}_c) + (\text{ML}_w * \text{ML}_c) + (\text{Ac} * 3) \quad (\text{Eq. 20})$$

Table 3.11: Floating TLP foundation component fabrication cost and weight to support a 5 MW turbine

Cost component for 5MW turbine	Cost per metric ton (2012\$)	Weight (metric tons)	Total cost, (\$ 2012)
TLP steel rate	\$4,361	1400	\$6,105,484
Mooring steel rate (high grade steel)	\$8,177	275*	\$2,248,672
Number of mooring lines/anchors	3		
Unit cost of anchors (gravity, suction, self-embedding anchors depending on soil type)	\$408,849		\$1,226,548
Total cost per foundation			\$9,580,704

*275 tons assumed for all three moorings based on the text

Source: Jacquemin et al. (2011)

Thus, \$9,580,704 is assumed to be the cost of each floating foundation. We then multiply this estimate by the number of floating foundations in each WEA.

3.1.6.6 Modeling Transmission Cable Cost

3.1.6.6.1 High-Voltage Alternating Current (HVAC)

For projects located less than 80 km from substations on shore, we assume that HVAC transmission cables would be used. In the case of New Jersey, where the New Jersey Energy Link is planned to connect the southern and northern part of the grid, the cables are assumed to connect to this offshore transmission cable. HVAC systems

do not require expensive converter equipment and thus are cheaper overall than HVDC systems for projects closer to shore (Elkinton et al., 2012). To estimate the number of cables needed to support each WEA, we determine the nameplate capacity in that area and divide the nameplate capacity by the cable capacity - 250 MW (Eq. 21).

$$\text{The number of cables per wind area} = \text{nameplate capacity in the area} / \text{cable capacity (Eq. 21)}$$

We assume that HVAC cables used here would be 220 kV 250 MW capacity with the cost between \$1,056,000/km and \$1,200,000/km (Elkinton et al., 2012). In our model, we used the average cost of \$1,128,000/km. The total cable cost per area is calculated with Eq. 22.

$$\text{Transmission cable cost} = (\text{length of cables} \times \$1,128,000/\text{km}) \times \text{number of cables (Eq. 22)}$$

3.1.6.6.2 High-Voltage Direct Current (HVDC)

For projects farther than 80 km from substations on shore, we assume that HVDC transmission cables would be used. This cable option is cost-effective for very large projects far from shore (Elkinton et al., 2012). We use the same technique as above for determining the number and the total cost of cables. We assume that the export cables used in this scenario will be 320 kV 500 MW cables. The cables would be based on the Voltage Source Converter (VSC) technology using extruded cross-linked poly-ethylene (XLPE) as the insulation medium (Elkinton et al., 2012). HVDC transmission cables are cheaper than HVAC cables, but more expensive converters are

required (these are not modeled). For our model we use the average cost of \$2,150,000/km based on the range of \$1,300,000 - \$3,000,000/km (Elkinton et al., 2012).

3.1.6.7 Modeling Transmission Cable Installation

The cost of transmission cable installation is calculated using the same average estimate of \$675,000/km for both HVDC and HVAC (Elkinton et al., 2012) (Eq. 23). This cost includes mobilization, route survey, engineering and testing, and other major services related to cable installation (Elkinton et al., 2012).

$$\text{Cable installation cost} = (\text{length of cables} \times \$675,000/\text{km}) \times \text{number of cables}$$

(Eq. 23)

3.1.6.8 Modeling Transportation Cost

3.1.6.8.1 Modeling the Cost of Transporting Turbines and Jacket Foundations

Transportation cost is modeled based on the data on operating cost of tugs provided by Weeks Marine, a US marine contractor. We measure the distance from the center of each WEA to a respective bay or harbor entrance. As it is uncertain which ports would be able to service wind project deployment, we use this distance as a proxy for the distance the vessels transporting wind turbine components would have to travel to deliver turbine components.

We assume that each trip a tug would be towing a feeder vessel (no-propulsion jack-up cleared of any equipment on deck) with 3 turbines or 3 foundations on board. We use the data in Table 3.12. The daily operating cost of a feeder vessel with no propulsion is approximately \$60,000 (Weeks Marine, 2012).

Table 3.12: Day rate (operating cost) and fuel cost and other parameters for a 6,000 horsepower tug

Vessel day rate (tugs, 6000 HP), \$	\$8,100
Hourly vessel rate, \$	\$338
Operating speed, knots	4
Estimated monthly fuel rate (\$3.25/gallon) at 80% Max load use	\$475,800
Fuel cost per day, \$	\$15,860
Fuel cost per hour, \$	\$661

Source: Weeks Marine (2012)

We estimate the number of hours each trip would take using the distance from each bay or harbor and vessel operating characteristics (Eq. 24).

$$\text{Time to the wind project site} = \frac{\text{average distance from bay or harbor}}{\text{operating speed}} \quad (\text{Eq. 24})$$

Using the above estimate, we calculate operating cost (including fuel) for each round trip by a tug towing a feeder vessel with 3 turbines or 3 foundations. This is calculated using Eq. 25, where t = time to the site. Even though the vessels would be returning empty and would be using less fuel than on the trip to the site, it is not feasible to estimate how much less based on the available data. Thus, we assume that the cost will be the same for the outbound and inbound trips. We calculate the cost of transporting all of the turbines for each WEA by multiplying the number of round trips needed to service each WEA by the cost per round trip.

$$\text{Transportation cost per round trip} = [(t * \text{operating cost/hour}) + (t * \text{fuel cost/hour})] * 2 \quad (\text{Eq. 25})$$

3.1.6.8.2 Modeling the Cost of Transporting Turbines Placed on Floating Foundations

To model the cost for transporting turbines placed on floating foundations, we assume that each machine would be towed with two tugs. No feeder vessels would be used. Thus, to approximate the cost of towing each turbine to the site, the operating and fuel cost per tug are doubled. The trip back is assumed to cost the same as to the project site. The calculations are performed using Eq. 25.

3.1.6.9 Modeling the Cost of Operation and Maintenance

Operation and maintenance (O&M) costs are modeled using first-order estimates converted to \$/MW/year (Jacquemin et al., 2011) (Table 3.13). Based on the experience from European wind projects, the O&M costs increase with distance from shore. For example, when wind projects are built farther than 50 km from shore, offshore base with helicopter support would be used.

Table 3.13: O&M costs at different distances from shore

	\$/MW/year (2012\$)
20 km - Onshore O&M base (\$/MW/annum)	\$73,947
50 km - Onshore O&M base (\$/MW/annum)	\$76,297
50 km - 150 km - Offshore base w helicopter support (\$/MW/annum)	\$88,066
>150 km - Offshore base, no helicopter support (\$/MW/annum)	\$91,766

Source: Jacquemin et al. (2011)

We assume that in the Mid-Atlantic, wind projects would be serviced using onshore and offshore O&M bases and helicopter/vessel support similar to that used for European projects. Specific locations of these future O&M bases in the Mid-Atlantic are uncertain. Therefore, to estimate O&M costs for each of SQ- and ALT-WEA, we measure the distance from the center of each wind area in a straight line to the coast of each state. Based on these measurements, we determine where our locations fit within the distance ranges in the table 17 above. We use the nameplate capacity in each WEA to calculate the O&M cost per year (Jacquemin et al., 2011). We multiply the annual cost for each area by 25 years to estimate the total operating cost for the life of a wind project (Eq. 26).

$$\text{O\&M cost for 25 years} = (\text{cost/MW/annum} \times \text{nameplate capacity}) \times 25 \text{ years}$$

(Eq. 26)

3.1.6.10 Modeling Capital Cost Payments from Offshore Wind Projects

To estimate the debt payments for wind CAPEX we make several assumptions. We assume that all wind projects would be financed with debt. We use the debt-financing rate obtained by Cape Wind – 7.5%²⁸ (Massachusetts Department of Public Utilities, 2012) and assume that the projects would be financed over 15 years (a term of debt) (Levitt et al., 2011; Mendelsohn, 2010). To estimate the combined payments on the debt incurred over 15 years, we use the formula for determining loan payments as described in Eq. 27 below, where a = interest rate; b = loan term period in years; c = present value of capital cost. Total debt incurred is estimated by multiplying the annual payment by 15 years.

$$\text{Annual debt payments for wind CAPEX} = \text{PMT}(a, b, c) \quad (\text{Eq. 27})$$

3.1.7 Modeling Changes in Vessel Emissions and their Social Costs

We assume that vessels would be using MDO/MGO fuel within the 370 km off the US coasts. Emission calculations for tug boats are conducted based on the daily

²⁸ Debt financing rates could depend on the market conditions and specific financing agreements. A Weighted Average Cost of Capital (WACC) of 9.8% (Levitt et al., 2011, p 6413) is used in the study on pricing of offshore wind power. WACC is defined as a “the weighted average of the required returns on the firm’s debt and equity as determined by the market... that can be taken as the minimum rate of return required to fund a project” (Levitt et al., 2011, p 6413). However, when a WACC of 9.8% is adjusted to real dollars (reduced by 2%) it closely resembles the Cape Wind financing rate. Therefore, in our analysis, we assume the debt rate obtained by Cape Wind. It is important to note that this financing rate is higher than the 6% rate assumed to be available for financing of new vessels. Thus, the debt rate of 7.5% reflects the increased risk currently associated with investing in wind projects.

fuel usage, because data on specific vessel characteristics needed for a more precise analysis using the propeller law are not available.

3.1.7.1 Modeling the Social Cost of Emissions from Commercial Ship Traffic

To calculate vessel emissions for the status quo and alternative routing scenarios, we use the estimates of fuel usage for each of the trips in our sample. We multiply the amount of fuel used per each trip by emission factors for NO_x, SO_x, PM, and CO₂ (Buhaug et al., 2009) (Table 3.14) (Eq. 28).

$$\text{Emissions of a pollutant per vessel trip} = \text{quantity of fuel used per trip} \times \text{emission factor (Eq. 28)}$$

Table 3.14: Emission factors (kg/metric ton fuel equivalent) in 2020 (except for CO₂). Emission factors for CO₂ are in kg of CO₂/kg of fuel. These are adjusted for the calculations of emissions added during rerouting

Pollutant	Emission factor
NO _x	49.1
SO _x	8.6
PM	1.6
CO ₂ (diesel distillates)	3.19

Source: Buhaug et al. (2009)

We calculate the social cost of vessel-generated emissions as follows. We multiply the tons of emissions produced by the average estimates of social cost per metric ton of each pollutant (Eq. 29) and then sum across pollutants. These are compiled from several sources (Table 3.15).

Social cost of emissions = total metric tons of fuel used x social cost/ton of
fuel (Eq. 29)

Table 3.15: Social cost of air pollutants (adjusted to 2012\$)

Pollutant	Cost per metric ton, in 2012\$			Source
	Low	High	Average	
SO ₂	\$2,704	\$26,031	\$14,368	EPA (2005)
NO _x	\$1,999	\$11,168	\$6,583	Gallagher (2005)
PM ₁₀	\$1,550	\$26,431	\$13,991	Boardman et al. (2011)
CO ₂			\$40	Interagency Working Group (2013)

We conduct a sensitivity analysis using the high estimates to account for the range in these costs and the inherent uncertainty in estimating these costs.

3.1.7.2 Modeling the Social Cost of Emissions from Transporting Turbine Components via Tugs

To model emissions generated by tugs during transportation of turbine components and foundations, we use data on daily fuel usage provided by Weeks Marine (Table 3.16).

Table 3.16: Tug characteristics. The fuel amount in gallons is converted to metric ton using the density of 0.981 grams/ml

Operating speed *(knots)	4
Max fuel burn (gallons/day)	6,000
Max fuel use (metric ton/day)	22.28

Source: Weeks Marine (2012)

Using the estimated daily fuel usage per tug, we calculate the hourly fuel usage. Using tug operating speed and distance to site, we estimate the number of hours each trip would take. We then calculate the fuel usage during each trip, multiply it by the emissions factors for NO_x, SO_x, PM, and CO₂ (Buhaug et al., 2009) and double it to determine emissions per round trip (Eq. 30).

$$\text{Emissions per tug round trip} = (\text{fuel used per trip} \times \text{emission factor}) \times 2$$

(Eq. 30)

Using the number of turbines, jackets, and floating foundations per wind area, we calculate the number of trips required to deliver all of the machines to each SQ and ALT-WEA. We calculate total emissions generated for all round trips for each wind area with Eq. 31.

$$\text{Emissions generated for all round trips in the area} = \text{emissions per round trip} \times \text{number of trips for each area (Eq. 31)}$$

The social cost of emissions is estimated using the average values per metric ton discussed above. We use high values in the sensitivity analysis.

3.1.7.3 Emissions during O&M for Wind Projects

Emissions generated during O&M for wind projects are not estimated due to the lack of data on engine power, fuel consumption rate etc. needed to calculate emissions. In the alternative scenario, wind projects would be located closer to shore, which would lead to reduced emissions from O&M vessels compared to the status quo scenario.

3.1.8 Estimating Impacts over the Duration of the Proposed Policy

The proposed policy spans 29 years. This accounts for 2 years of wind project construction, 25 years of project operation, and 2 year of project decommissioning.

3.1.8.1 Time Structure of Costs and Benefits

The added costs to vessel operators would start accruing at the start of 2020 with the beginning of project construction. These costs would continue accruing through 2048. The annual added costs are adjusted given the projection that the number of vessels in the East Coast container fleet would double by 2035 (increase by 2.2% annually) (USACE, 2012). Based on this projection, we assume that the number of all vessel trips affected by the rerouting scenario would increase by 2.2% annually. Thus, the annual number of vessel trips and the annual vessel cost is assumed to grow at 2.2% annually.

Benefits in the form of reduced project capital expenditures and reduced emissions from tugs would also start accumulating in 2020. These benefits will spread over 2 years. We assume that all of the projects would be built in 2 years. This assumption reduces the need to calculate offshore wind capital costs in increments making further assumptions about the time of the build-outs and their sizes. Benefits in the form of reduced O&M expenditures and debt payments would start accruing in

2022 after the projects are installed. These would spread over 25 years. Due to limited O&M cost data, operating costs are assumed to stay flat throughout the life of wind projects, though it is feasible that these costs would increase over time.

3.1.8.2 Discounting and Calculating Net Present Values

The policy requiring vessels to reroute would be implemented starting at the beginning of 2020. These values are estimated as follows:

- 1) To control for the declining purchasing power of the dollar due to inflation, nominal dollar values are brought into 2012 real (constant) dollars using the Consumer Price Index (CPI) method (Boardman et al., 2011). The CPI is published monthly by the US Bureau of Labor Statistics and is expressed as the ratio of the cost of buying a standard basket of market goods in a particular year to the cost of purchasing the same or similar basket of goods in the base year (1980), multiplied by 100 (Boardman et al., 2011).
- 2) To convert Euros to US dollars, we use the European Central Bank exchange rate for 2011 (ECB, 2012). Then we convert US dollar values to 2012\$ using the Consumer Price Index from the Bureau of Labor Statistics²⁹ (BLS, 2012).
- 3) To convert 20xx nominal dollar amounts into real 2012 dollars, we divide the 20xx dollar amounts by the CPI for 20xx (xxx.xxx) and multiply by the CPI for

²⁹Bureau of Labor Statistics (BLS, 2012)
<ftp://ftp.bls.gov/pub/special.requests/cpi/cpiiai.txt>

2012 (229.594) (BLS, 2012) (Eq. 32). These adjusted 2012\$ amounts are used in our model.

$$\text{Real 2012\$} = \text{nominal 20xx\$} / \text{CPI 20xx} \times \text{CPI 2012} \quad (\text{Eq. 32})$$

- 4) Present values of costs and benefits are calculated based on Eq. 33 and 34 (Boardman et al., 2011) below. We assume that interest is compounded once per period (one year). B_t and C_t denote benefits and costs incurred in period $t = 0, 1, \dots, n$, with i that represents the discount rate (Eq. 33). We use a real social discount rate (SDR) of 3.5% (Boardman et al., 2011). This SDR is chosen based on the notion that, for projects that do not have impacts extending beyond 50 years, effects are intragenerational. Sensitivity analysis using a discount rate of 10% is also performed.

$$PV(B) = \sum_{t=0}^n \frac{B_t}{(1+i)^t} \quad PV(C) = \sum_{t=0}^n \frac{C_t}{(1+i)^t} \quad (\text{Eq. 33})$$

- 4) After the present value of costs and benefits are calculated, we estimate net benefits (Eq. 34) (Bordman et al., 2011) and calculate the benefits-cost ratio. As we only propose one alternative, we compare the estimated benefits to the status-quo scenario.

$$NPV = \sum_{t=0}^n \frac{NB_t}{(1+i)^t} \quad (\text{Eq. 34})$$

3.1.8.3 Robustness of the Model and Sensitivity Analysis

Due to inherent uncertainties regarding the cost of offshore wind projects, cost of bunker fuel, operating and capital costs as well as the social cost of air emissions, we conduct a sensitivity analysis. Sensitivity analysis is a systematic approach used to examine how the outcome of a CBA changes with variations in assumptions, inputs, or study design.

We use the following inputs for the sensitivity analysis:

- 1) The number of affected vessel trips is doubled to account for uncertainty in the number of total affected ships.
- 2) The cost of steel for foundations, the cost of floating foundations, transmission cables are doubled to account for the possible market changes and innovations that would lead to reductions in wind project cost.
- 3) The cost of bunker fuel is doubled to account for uncertainty in the crude oil market. This fuel price increase is expected by some shippers with the introduction of 2015 regulations to reduce sulfur content to 0.01% in fuel used by vessels operating within the North American Emissions Control Area (ECA).
- 4) The high values for social cost of emissions are used to account for the inherent uncertainty regarding these values.

6) A discount rate of 10%.

The results of our model are discussed in the next Chapter.

Chapter 4

RESULTS

The results of our analysis are presented as follows. First, we list the added direct and indirect costs of vessel rerouting. We then highlight the direct and indirect benefits (cost savings) from building offshore wind projects closer to shore. We follow with estimates of the net present value of net benefits. Then, we present the results of a sensitivity analysis based on assumptions that the costs of transits for ships would increase and the cost of building projects farther from shore would decrease. As this is a first order analysis, our objective is not so much to provide the most refined and detailed estimates, but rather, to offer a considerable insight into the societal implications of the proposed policy change.

4.1 Costs

The added costs of rerouting ship traffic are comprised of direct and indirect costs. The direct costs include fuel, operating and capital costs. The indirect costs include the social cost of emissions generated during the ships' extra operating time. Other costs to vessel operators are outside of the scope of the study. Here, we first list annual added costs and then provide the total costs during 29 years of the proposed policy.

In 2009, large deep-draft ships engaged in foreign trade traveling between the Mid-Atlantic ports completed 1,488 trips. Nine percent of trips were completed by tankers; 72% by container ships; 12% by vehicle carriers; 4% by bulk carriers; and 3%

by general cargo. This number of transits would be affected annually if all ALT-WEAs were moved closer to shore, adding an average distance of 18.5 km per vessel trip.

We first calculate the added costs to vessel operators as based on the number of vessel trips taken in 2009. During 29 year of the proposed policy, this cost is expected to increase annually. We base this assumption on the projection that the number of vessels in the East Coast container fleet would double by 2035 (increase by 2.2% per year) (USACE, 2012). Unfortunately, we do not have access to projections regarding the expected number of trips completed in the area during this period. Thus, we assume that the number of the affected transits between the Mid-Atlantic ports would also double by 2035, increasing by 2.2% annually. Though a conservative estimate, we safeguard against underestimating the impacts of the proposed policy.

4.1.1 Annual Added Costs

The added costs listed below represent the approximate annual added costs for ships traveling along these routes in 2009, prior to the assumed increase in the number of vessels as discussed above (Table 4.1). Therefore, for the ships transiting between New York/New Jersey and the Delaware Bay, the proposed rerouting scenario would generate an added cost of \$2.9 million (in 2012\$) annually. Fuel cost would account for \$1.5 million, other operating costs - \$0.1 million, capital cost - \$0.2 million, and social cost of emissions for \$1 million. For the transits between New Jersey/New York and Chesapeake Bay, the added total cost of rerouting is \$6.7 million (in 2012\$), with \$3.7 million attributed to fuel, \$0.16 million to operating costs, \$0.3 million to capital cost and \$2.5 million represent the social cost of emissions. Vessels transiting between Delaware and the Chesapeake Bays would incur an additional \$0.16 million

in cost, with fuel cost of \$0.09 million, operating cost of \$0.01 million, capital cost - \$0.01 million and social cost of \$0.06 million.

Table 4.1: Summary of added annual cost during rerouting based on the number of trips taken in 2009, in 2012\$ before discounting

Route	Added Fuel Cost, mln	Added Operating Cost, mln	Added Capital Cost, mln	Added Social Cost, mln	Total Added Cost, mln
NY/NJ – DE Bay	\$1.5	\$0.1	\$0.2	\$1.0	\$2.9
NY/NJ - CH Bay	\$3.7	\$0.16	\$0.3	\$2.5	\$6.7
DE Bay – CH Bay	\$0.09	\$0.01	\$0.01	\$0.06	\$0.16
Total	\$5.29	\$0.27	\$0.51	\$3.56	\$9.76

As discussed above, we assume that the number of vessel trips along the affected routes increases by 2.2% annually. Thus, in 2020, the first year the policy would be in effect, the added annual cost for all vessels would reach \$13 million (in 2012\$, before discounting) (Table 4.2). The added cost is assumed to increase annually, and in 2048, it would reach \$24 million (in 2012\$, before discounting) per year for all affected ship transits (Table 4.2).

Fuel (54%) and social costs of emissions (36%) are the largest components of costs incurred during rerouting. Operating cost and capital cost payments constitute 7% and 3% of the total costs respectively. Thus, 36% of the added costs that would come from the damages associated with the increased air pollution would be borne by the public at large rather than by shippers.

Table 4.2. Added annual cost of vessel rerouting during the 29 years of project operation (escalated at 2.2% annually starting in 2012)

Cost of rerouting, 2012\$	
Cost of rerouting (2020), \$	\$13,079,701
Cost of rerouting (2021), \$	\$13,367,454
Cost of rerouting (2022), \$	\$13,661,538
Cost of rerouting (2023), \$	\$13,962,092
Cost of rerouting (2024), \$	\$14,269,258
Cost of rerouting (2025), \$	\$14,583,182
Cost of rerouting (2026), \$	\$14,904,012
Cost of rerouting (2027), \$	\$15,231,900
Cost of rerouting (2028), \$	\$15,567,002
Cost of rerouting (2029), \$	\$15,909,476
Cost of rerouting (2030), \$	\$16,259,484
Cost of rerouting (2031), \$	\$16,617,193
Cost of rerouting (2032), \$	\$16,982,771
Cost of rerouting (2033), \$	\$17,356,392
Cost of rerouting (2034), \$	\$17,738,233
Cost of rerouting (2035), \$	\$18,128,474
Cost of rerouting (2036), \$	\$18,527,300
Cost of rerouting (2037), \$	\$18,934,901
Cost of rerouting (2038), \$	\$19,351,469
Cost of rerouting (2039), \$	\$19,777,201
Cost of rerouting (2040), \$	\$20,212,300
Cost of rerouting (2041), \$	\$20,656,970
Cost of rerouting (2042), \$	\$21,111,423
Cost of rerouting (2043), \$	\$21,575,875
Cost of rerouting (2044), \$	\$22,050,544
Cost of rerouting (2045), \$	\$22,535,656
Cost of rerouting (2046), \$	\$23,031,440
Cost of rerouting (2047), \$	\$23,538,132
Cost of rerouting (2048), \$	\$24,055,971
Total, \$	\$522,977,344

4.1.2 Total Added Costs

We assume the rerouting policy would be in effect for 29 years (25 years of wind project operation, plus 2 years each for installation and decommissioning). Over 29 years, the added direct and social cost of vessel rerouting would add to almost \$523 million (in 2012\$, before discounting) (Table 4.2).

4.2 Benefits

The benefits in the study represent cost savings from building offshore wind projects closer to the coast in shallower waters. Ultimately, the direct societal benefits would come from offshore wind generated electricity that would be cheaper compared to that from the far-shore projects. These reduced costs (direct benefits) would come from reduced capital and operating expenditures, as well as from reduced debt for wind project financing. Indirect benefits would come in the form of the reduced damages from emissions generated by tug vessels transporting wind turbine components or foundations. Below, we summarize the benefits from moving WEAs closer to shore after vessels are rerouted. We list direct and indirect benefits by wind energy area for the status quo and alternative scenarios. All wind costs are converted to 2012\$.

4.2.1.1 New Jersey WEA

The area of both the New Jersey SQ-WEA and A-WEA is 1,126.8 km.² 1,109 5 MW wind turbines with a spacing of 8 x 8 rotor diameters can be installed within, totaling at 5,545 MW of nameplate capacity. As fewer turbines would be needed to generate the comparable amount of power at the SQ location, the SQ-WEA houses 1,037 turbines with 5,185 MW in capacity. The A-WEA would be relocated closer to shore, reducing the average distance to the New Jersey Energy Link (NJEL) by 35.5

km³⁰. The average distance to the port area of NY/NJ that would be covered by the tugs transporting turbine components is reduced by 22.4 km³¹. The average distance to the potential O&M area (located directly across from the center of the WEA) is reduced by 34 km³². Jackets replace floating platforms in the alternative scenario.

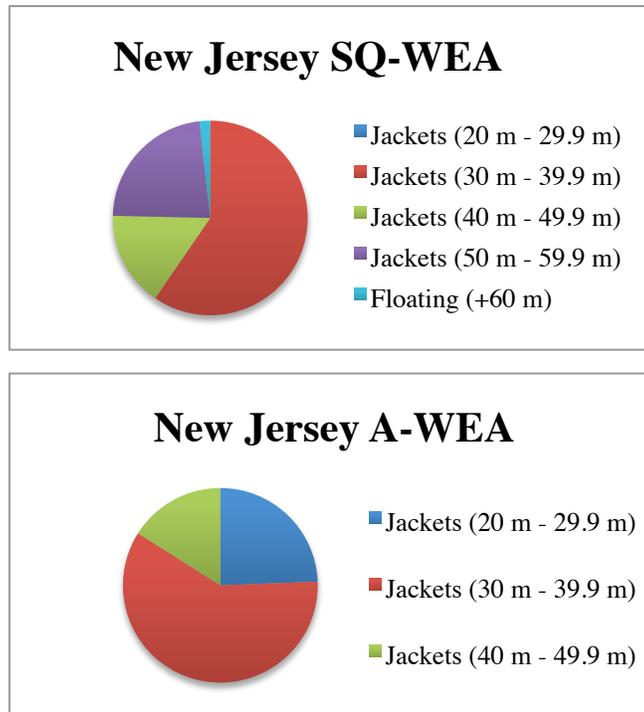


Figure 4.1: Foundation types for SQ and ALT-WEA off New Jersey

³⁰ From 49.5 km to 14 km

³¹ From 146.3 km to 123.9 km

³² From 81.4 km to 47.4 km

Table 4.3 below summarizes the cost of different wind project components for the NJ SQ and A-WEA and illustrates the relationship between cost, distance and water depth in \$billion (2012). These and other estimates in the tables below are rounded.

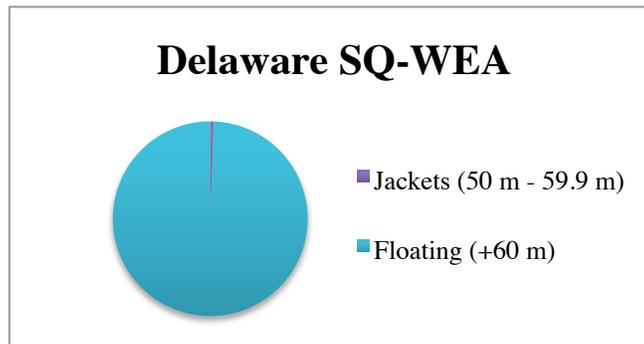
Table 4.3: New Jersey WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$

New Jersey WEA	SQ	ALT	Savings
Foundations, \$	\$3.9	\$4.4	\$0.4
Transmission cables, \$	\$1.2	\$0.4	\$0.8
Transmission cable installation, \$	\$0.7	\$0.2	\$0.5
Transportation during construction and decommissioning, \$	\$0.18	\$0.16	\$0.02
O&M, \$	\$11.4	\$10.6	\$0.8
Capital cost payments (debt), \$	\$11.0	\$8.6	\$2.4
Social cost of emissions from transportation during construction and decommissioning, \$	\$0.032	\$0.028	\$0.004

The major cost savings stem from the cost of procuring transmission cables (approximately \$800 million) and their installation (about \$500 million). O&M cost savings amount to about \$1.3 billion during the life of the project (Table 4.3). Benefits from reduced distance for transportation during project construction and decommissioning add to approximately \$20 million. The value of debt payments for capital costs amounted to a significant portion of the overall costs, reaching \$2.4 billion over 25 years. The social cost of emissions during transportation during project construction and decommissioning is reduced by \$4 million. To summarize, the total direct and indirect cost savings for the NJ WEA add to almost \$5.2 billion.

4.2.1.2 Delaware WEA

The area of the Delaware WEA would be 741.7 km². The A-WEA could house 730 turbines, with the nameplate capacity of 3,650 MW. In the SQ-WEA, fewer turbines would be needed to generate the comparable amount of power. Thus, the SQ-WEA would house 682 turbines, adding to 3,408 MW. For the A-WEA, the average distance to the on-shore grid would be reduced by 77 km³³. The average distance to the Delaware Bay entrance would be reduced by 70.4 km³⁴. The average distance to the potential O&M area located on the DE shore is reduced by 78.4 km³⁵. Floating substructures are the main foundation technology utilized in the SQ area. In the alternative, only jacket foundations would be used. The breakdown by foundation type is shown in Figure 4.2 below.



³³ From 143.8 km to 66.2 km

³⁴ From 138.4 km to 68 km

³⁵ From 144.4 km to 66 km

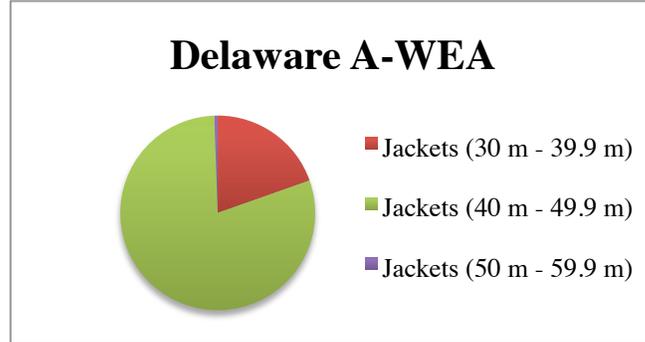


Figure 4.2: Foundation types for SQ and ALT-WEA off Delaware

Table 4.4 below summarizes the costs and cost savings for the DE SQ and A-WEA. The cost of foundations costs and cable installation is reduced by approximately 50%. The cost of transmission cables is reduced by approximately \$1 billion or by almost 70%. The cost of O&M increases slightly to about \$0.6 billion over 25 years in the alternative scenario, as more turbines would be serviced. The increase can also be potentially attributed to the fact that the O&M cost data covered only three different distance ranges³⁶. This data does not allow for more precise calculation. Transportation costs during project construction and decommissioning are reduced by about \$42 million. The savings in debt payments for capital costs amount to \$8 billion over 25 years. Also, the social cost of emissions during the construction and decommissioning is reduced by \$30 million. To summarize, the total direct and indirect cost savings for the DE WEA are approximately \$12.5 billion.

³⁶ Unfortunately, no specific per km O&M costs could be calculated based on the \$/MW/year data for three distance ranges: for <50 km, 50 to 150 km, >150 km from shore.

Table 4.4: Delaware WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$

Delaware WEA	SQ	ALT	Savings
Foundations, \$	\$6.5	\$2.7	\$3.8
Transmission cables, \$	\$2.1	\$1.1	\$1.0
Transmission cable installation, \$	\$0.66	\$0.65	\$0.01
Transportation during construction and decommissioning, \$	\$0.1	\$0.06	\$0.04
O&M, \$	\$7.5	\$8	-\$0.6
Capital cost payments (debt), \$	\$15.8	\$6.6	\$8.2
Social cost of emissions from transportation during construction and decommissioning, \$	\$0.06	\$0.04	\$0.02

4.2.1.3 Maryland and Virginia WEAs

In the status quo scenario, we assume that two separate WEAs would be established off the coast of Maryland and Virginia. In the alternative scenario, the two areas would be combined into a single WEA. The combined MD/VA A-WEA would be 1,334.4 km². The A-WEA would house 1313 turbines, with the nameplate capacity of 6,571 MW. In the status quo scenario, the WEAs would house fewer turbines: MD - 689 turbines (3,447 MW); VA - 566 turbines (2,830 MW). The A-WEA would be located 55 km from the on-shore grid, compared to 105 km (MD) and 118 km (VA).

The combined A-WEA would be 122.4 km from the Chesapeake Bay entrance. However, the northern and the southern boundaries would be significantly closer to either the Delaware Bay or the Chesapeake Bay entrances. Distance to the potential O&M area would also be reduced to 54.8 km, compared to 103.5 km off MD and 78.1 km off VA.

In the status quo scenario, floating foundations would be used for projects within the MD SQ WEA. Deep-water jackets and some floating platforms would be

used for projects within the VA SQ-WEA. In the alternative scenario, the combined A-WEA would house turbines located primarily on jackets in waters with less than 50-meter depth (Figure 4.3 below).

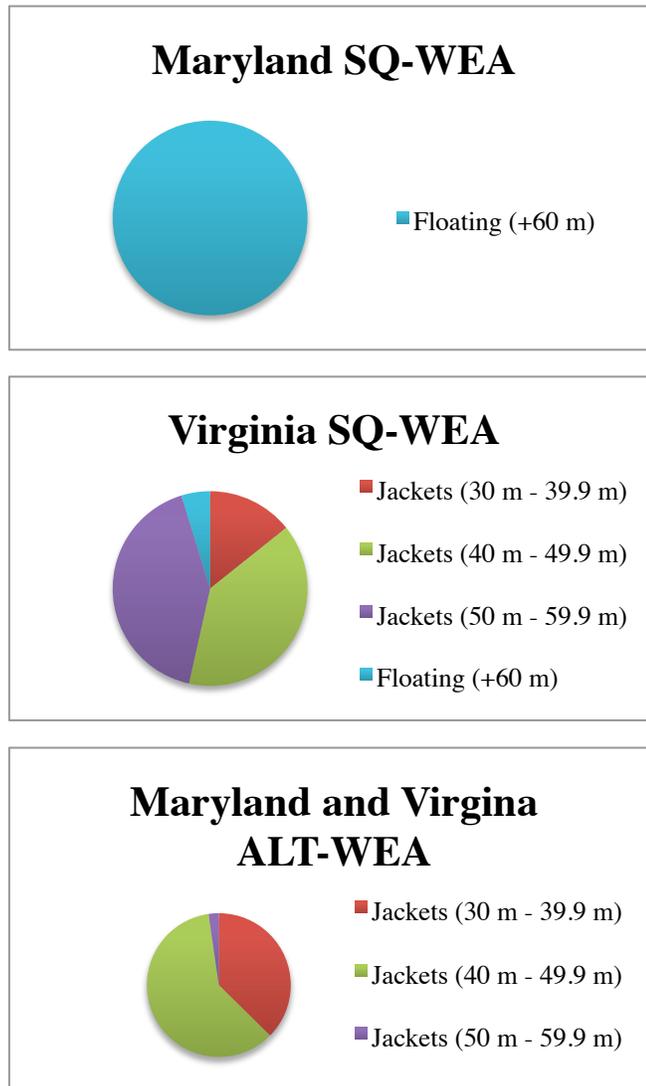


Figure 4.3: Foundation types for SQ and ALT-WEA off Maryland and Virginia

Table 4.5 below summarizes the cost savings for the MD and VA SQ and A-WEA. As all of the floating substructures are replaced with significantly cheaper jackets, the largest savings come from foundations (\$6.3 billion). Other benefits include the reduced cost of procuring transmission cables (\$1.5 billion) and cable installation expenditures (almost \$1 billion). The social cost of emissions from tug travel during construction and decommissioning would be reduced by \$60 million.

As in the case of Delaware WEA, O&M would be slightly more expensive in the alternative WEA, increasing by \$0.6 billion over 25 years³⁷. Reduced debt amounts to \$14 billion over 25 years. Relocating the WEA closer to shore would lead to about \$92 million saved from transportation during project construction and decommissioning and approximately \$30 million in reduced social cost of air emissions from this activity. To summarize, the total direct and indirect cost savings for the MD/VA WEA are approximately \$23 billion.

³⁷ The cost of O&M increased slightly due to the higher number of turbines in the alternative area and because the SQ and A-WEAs fell into the same distance range: 50 to 150 km from shore.

Table 4.5: Maryland and Virginia WEA costs and cost savings over the 25-year life of the project. All values are in billion 2012\$

Maryland and Virginia WEAs	SQ	ALT	Savings
Foundations, \$	\$9.1	\$2.8	\$6.5
Transmission cables, \$	\$3.0	\$1.7	\$1.3
Transmission cable installation, \$	\$0.93	\$0.97	-\$0.04
Transportation during construction and decommissioning, \$	\$0.2	\$0.12	\$0.09
O&M, \$	\$13.8	\$14.5	-\$0.7
Capital cost payments (debt), \$	\$22.2	\$8.9	\$13.3
Social cost of emissions from transportation during construction and decommissioning, \$	\$0.13	\$0.07	\$0.06

4.2.2 Added Benefits (Cost Savings) for All WEAs before Discounting

Based on the estimated capital, O&M, debt and social costs of the wind projects built at the modeled distances and water depths, we highlight the cost savings produced in the alternative scenario (Table 4.6).

Table 4.6: The estimated direct and indirect benefits for WEAs. All values are in billion 2012\$ before discounting

	Capital	O&M	Capital Cost Payments	Social	Total
NJ	\$1.74	\$0.8	\$2.94	\$0.004	\$5.5
DE	\$4.84	-\$0.6	\$8.19	\$0.03	\$12.5
MD/VA	\$7.89	-\$0.7	\$13.3	\$0.06	\$20.6
Total	\$14.46	-\$0.5	\$24.5	\$0.094	\$38.5

We organize costs and benefits according to the wind project construction timeline (Table 4.7). The shipping operators would accrue the costs annually. The

capital cost savings would be front-loaded, occurring in the first two years of project construction. The savings in terms of O&M and debt payments, as well as the indirect benefits would accrue annually during 25 years of wind projects operating (Table 4.7). The savings during decommissioning would be seen during the last two years.

Table 4.7: Summary of annual costs and benefits and the present value calculation

	Annual Added Costs, MILLION	Annual Benefits, BILLION	Annual Net Benefits, BILLION
Period 1 (2020), \$	\$13.08 Million	\$7.2 Billion	\$7.21 Billion
Period 2 (2021), \$	\$13.37	\$7.2	\$7.21
Period 3 (2022), \$	\$13.66	\$0.96	\$0.94
Period 4 (2023), \$	\$13.96	\$0.96	\$0.94
Period 5 (2024), \$	\$14.27	\$0.96	\$0.94
Period 6 (2025), \$	\$14.58	\$0.96	\$0.94
Period 7 (2026), \$	\$14.90	\$0.96	\$0.94
Period 8 (2027), \$	\$15.23	\$0.96	\$0.94
Period 9 (2028), \$	\$15.57	\$0.96	\$0.94
Period 10 (2029), \$	\$15.91	\$0.96	\$0.94
Period 11 (2030), \$	\$16.26	\$0.96	\$0.94
Period 12 (2031), \$	\$16.62	\$0.96	\$0.94
Period 13 (2032), \$	\$16.98	\$0.96	\$0.94
Period 14 (2033), \$	\$17.36	\$0.96	\$0.94
Period 15 (2034), \$	\$17.74	\$0.96	\$0.94
Period 16 (2035), \$	\$18.13	\$0.96	\$0.94
Period 17 (2036), \$	\$18.53	\$0.96	\$0.94
Period 18 (2037), \$	\$18.93	\$0.96	\$0.94
Period 19 (2038), \$	\$19.35	\$0.96	\$0.94
Period 20 (2039), \$	\$19.78	\$0.96	\$0.94
Period 21 (2040), \$	\$20.21	\$0.96	\$0.94
Period 22 (2041), \$	\$20.66	\$0.96	\$0.94
Period 23 (2042), \$	\$21.11	\$0.96	\$0.94
Period 24 (2043), \$	\$21.58	\$0.96	\$0.94
Period 25 (2044), \$	\$22.05	\$0.96	\$0.94

Period 26 (2045), \$	\$22.54	\$0.96	\$0.94
Period 27 (2046), \$	\$23.03	\$0.96	\$0.94
Period 28 (2047), \$	\$23.54	\$0.06	\$0.04
Period 29 (2048), \$	\$24.06	\$0.06	\$0.04
Total, \$	\$523 million	\$38.4 billion	\$37.9 billion

4.3 Present Value of Net Benefits

The proposed changes to the vessel routes would come into effect in 2020 and would continue for 29 years. Since the effectiveness of the proposed vessel rerouting is determined today, we calculate the present value of the future costs and benefits to translate the real values in 2012\$ accumulated over the 29 years of the proposed policy alternative into the current values. We use the social discount rate of 3.5% based on the methodology in Boardman et al. (2011).

The present value (PV) of the total added rerouting cost is approximately \$193 million (in 2012\$). The PV of benefits amounts to \$14.2 billion (in 2012\$). Thus, the benefits of the proposed policy significantly outweigh the costs (Table 4.8).

Table 4.8: Present value costs, benefits and net benefits (3.5% social discount rate)

Present value of total added cost, \$	\$0.193 billion
Present value of total added benefits, \$	\$14.15 billion
Present value of net benefits, \$	\$13.98 billion
Benefit-cost ratio	73:1

4.4 Sensitivity Analysis

To test the robustness of the findings, we perform a sensitivity analysis. We run the model based on assumptions that the cost of rerouting ships would increase in

the future, while the cost of building wind projects in deeper waters farther from shore would decrease. We:

- 1) Double the cost of fuel;
- 2) Cut in half the cost of steel for jacket fabrication, floating foundations and the cost of transmission cables;
- 3) Use the higher end values of the social cost of emissions; and
- 4) Use the high 10% social discount rate.

With these parameters, the combined cost accrued during 29 years the policy would be in effect amounts to \$934 million, compared to \$523 million previously (2012\$, before discounting). The benefits decrease by approximately \$18 billion to slightly less than \$20 billion (in 2012\$ before discounting). However, even with a high 10% social discount rate, this alternative scenario still yields significant net benefits of approximately \$1.7 billion (discounted to 2012\$). Benefits would outweigh the cost 21:1. Even if the number of affected vessels were to quadruple, the net benefits would amount to \$1.5 billion (2012\$, with the high 10% SDR), still outweighing the costs 5:1.

In the next chapter, we discuss these results and suggest model improvements and areas for future research.

Chapter 5

DISCUSSION AND CONCLUSIONS

5.1 Overview

The goal of this study is to provide a preliminary framework, methodology and the first-order estimates of the net societal benefits of the proposed policy change: to reroute some of the vessel traffic to open areas for wind development in the US Mid-Atlantic. The analysis is based on previous studies that provide methodologies to estimate vessel rerouting costs, external cost of air emissions, and on research quantifying the relationship between distance and water depth and the cost of offshore wind projects. Utilizing this past research, we develop a model that estimates: 1) direct added cost for shippers, 2) direct cost savings for wind project developers, 3) indirect costs from added air emissions from the rerouted ships and 4) indirect benefits from reduced emissions from tugs transporting wind turbine components.

5.2 Wind Project Components that Are Not Monetized

Some costs and benefits are not monetized due to data limitations. We do not estimate the effects of potential delays and the effects of vessel operators deciding not to call on the Mid-Atlantic ports. These CBA components are outside of the scope of our analysis. Vessel emissions generated during O&M are not monetized, as we do not have data on O&M vessel characteristics (engine power, fuel consumption rate etc.) needed to calculate emissions. The cost of procuring and installing electrical

substations is not estimated due to the lack of data. Including these components in the study would further increase the net benefits from the proposed policy alternative.

5.2.1 Putting the Findings into Context

To illustrate how the proposed alternative could translate into the actual costs and benefits to consumers, we calculate several metrics. The full description of methods used to calculate this value can be found in the Appendix. It is important to note that in this study we are comparing an existing and a future use with numerous assumptions about the future. Thus, the examples below are illustrations of how the estimated costs and benefits could be translated into the effects on consumers.

5.2.1.1 The Added Cost per Metric Ton of Goods Transported

The proposed rerouting measure would increase the social cost per trip by about \$7,400 from approximately \$86,000³⁸. Thus, the private cost per trip would increase by approximately \$4,700; the external cost of emissions - about \$2,700. Dividing the total annual added cost of rerouting by the total tons transported by the affected vessels translates into an increase in the cost of transporting a metric ton of goods by 39¢. However, the private added cost incurred by the shippers would amount to 25¢, with the remainder representing the social cost of added emissions.

5.2.1.2 Additional Wind Capacity that Could Be Built with the Benefits

The power generated in the proposed WEAs is sufficient to serve approximately 4.2 million households annually (based on 2011 demand). The benefits

³⁸ An average across all routes and vessel types; the cost of distance traveled between the TSSs only.

could be used to build an additional 2,309 MW of wind capacity, assuming that building this additional capacity would carry the cost of building shallow-water projects - approximately \$6 million/MW³⁹ in 2012\$. This additional 2,309 MW of offshore wind capacity would power an additional 612,000 households. Thus, these societal benefits could be invested into the further development of offshore wind capacity, reaping additional benefits of reduced air pollution, increased energy security and boosting domestic manufacturing.

5.2.1.3 Displaced CO₂ if Additional Wind Capacity is Built

We also calculate the amount of CO₂ that could be displaced if 2,309 MW of additional wind capacity could be built. During 25 years of wind project operation, approximately 137 million tons of CO₂ would be displaced.

5.2.1.4 Reduction in the Cost of Power if the Near-Shore Wind Areas Are Developed

We also attempt to put the findings in context for the electricity customers in the US Mid-Atlantic. For this, we calculate how the proposed policy would impact a customer's electricity bill should they consume electricity generated in the alternative WEAs rather than in the status quo WEAs. We estimate that a household with average electricity consumption could save \$30 monthly and \$360 annually. This amounts to a reduction of 3 cents for every kWh.

³⁹ Based on Levitt et al. (2011) that used the \$5750/kW in 2010\$

5.2.2 Uncertainties, Model Improvements and Future Research

As the model consists of three components, estimating direct effects on shippers and offshore wind project developers, and indirect impacts in the form of air emissions, we discuss model shortcomings and suggest improvements for each of the components.

5.2.2.1 Vessel Costs

We use the available data on the number of ships transiting between the US Mid-Atlantic ports, but could not verify the final number of affected vessels against any other source. Our final vessel sample comes from the combination of the Automatic Identification System (AIS) (2009), the US Army Corps (USACE) (2009), and the Lloyds register (2004) datasets. Each data source has records missing data. This reduces the confidence in the number of affected vessel trips. Furthermore, the 2004 Lloyds register dataset with vessel characteristics is almost 10 years old. The dataset also has many incomplete fields for main and auxiliary engine sizes, which are used to estimate fuel consumption. Thus, we use averages.

Furthermore, to estimate operating and capital costs we rely on publically available data sources, which though helpful, may not account for all of the costs. Some of the datasets containing more complete information on vessel movements and costs have been compiled by the USACE and other federal agencies, yet are not available for public use. Having access to these data would significantly improve the confidence of this and other analyses.

Fuel costs also represent another uncertainty. It is difficult to predict how the global bunker fuel prices will change over the next several decades. This uncertainty is exacerbated by the recent establishment the North American Emissions Control Area

(ECA). Under the ECA, starting in 2015, vessels would be required to use fuel with less than 0.1% sulfur content within 200 nautical miles of the US coast. Thus, some industry experts expect fuel prices to double in 2015. We account for this possible increase in the sensitivity analysis. However, even with this increase, vessel costs are still a fraction of the benefits of building offshore wind projects closer to shore.

Furthermore, we do not estimate the full market costs incurred from vessel rerouting. Even though ships would have perfect information regarding the location of the wind areas they need to avoid and would plan their trip accordingly, they could still be delayed. Vessels could miss their tide windows, arriving at the docks several hours later. This in turn could require hiring extra stevedores working overtime to unload a delayed shipment. Also, the increased cost per trip could lead some operators to add extra ships to service the route, adding to the shipper's expense. Here, we assume that the proposed modification is not a significant enough diversion for the vessel operators to add extra ships to the affected routes.

Lastly, as we focus on the effects of rerouting on deep-draft commercial vessels, we do not conduct the analysis for passenger ships, smaller domestic vessels, recreational craft, fishing boats, barges, tugs etc. However, even if the number of affected vessels was to increase 50-fold, the policy would still produce significant net societal benefits of \$5.4 billion (in 2012\$).

5.2.2.2 Wind Project Costs

Offshore wind cost data has inherent uncertainties, especially considering that no project has been built in the United States. In the study, we use primarily the data compiled by the National Renewable Energy Laboratory (NREL). Where NREL's estimates are not available, we use data from European projects and estimates

generously supplied by our US industry partners. As most studies provide ranges of costs, we use averages in our model. As with many studies citing offshore wind capital and operating expenditures, we emphasize that the values used here are general estimates and not specific project costs, which can vary widely based on the project location and characteristics. In particular, O&M costs that are based on data from European projects provided for only three distance ranges do not provide sufficient precision to establish a more detailed distance-to-cost relationship. Additionally, costs depend on the price of raw materials such as steel, and on market conditions, such as interest rates, construction vessel availability, etc.

5.2.2.3 Indirect Costs of Air Emissions

After fuel expenditures, the indirect cost of air emissions represents the second largest component of the total social costs of rerouting ships. These external costs are to a certain extent ameliorated by the reduced travel by tugs during wind project construction. As the values vary widely, we use averages of the available estimates of the external costs per ton for each air pollutant. Refining these estimates could be valuable, but would not reverse the final outcome of this analysis.

5.2.2.4 Future Areas of Research

Further research could concentrate on analyzing the legal mechanism that would be needed to implement the proposed rerouting scenario. This would inform the complexities and potential legal challenges of establishing wind energy areas far from shore. Additional research could also evaluate other impacts on the market that would result from vessel rerouting, such as cost of delays, as well as estimate the economic impact on fishing, passenger, recreational ships and barge and tug traffic. Furthermore,

future research could estimate the additional benefits of directing vessels to transit farther from shore. This includes having air pollutants discharged farther from the coast, causing fewer health effects than if they were emitted closer to shore (Winebrake et al., 2009; Camping et al., 2013). We do not quantify or monetize these effects due to the complexity of pollutant transport science and the exposure-response functions and their effects on human health.

5.2.3 Policy Recommendations and Conclusions

We argue that our study results are robust, and therefore, we contend that establishing a policy that would redirect deep-draft vessel traffic transiting between the Mid-Atlantic ports farther from shore would yield tremendous societal benefits. Our analysis provides estimates needed to effectively reconcile the society's need for commercial navigation with the interest in development of offshore wind energy, which is critical to meeting the national goals of increasing energy security, reducing pollution, mitigating climate change and boosting the US economy.

The study also complements the current US Coast Guard's Port Access Route Study (PARS) efforts to determine the effects of offshore renewable energy development on coastwise shipping and safety of navigation along the US Atlantic Coast. While conducting the PARS, the Coast Guard stated the need for the analysis of economic effects of modifications of the vessel management systems. Even though we only evaluate the effect of the rerouting on a limited number of ships in one region of the Mid-Atlantic⁴⁰, the study highlights the economic effects of the vessel routing

⁴⁰ Other vessels that are using portions of this route on their longer voyages and would have to travel around the ALT-WEAs would also incur some additional costs. However, their diversion would be a small fraction of the proposed diversion for the

modifications that could be considered by the Coast Guard. Furthermore, our findings clearly suggest that the added cost of less than \$1 for transporting a ton of goods is minimal.

We anticipate that, as with many policies, some vessel operators will at first be reluctant to modify their established routes. They may argue that our economic effects are underestimated and that through this policy, vessel owners are once again being asked to bare an economic burden of a government regulation. Similar arguments were voiced when speed restrictions at certain times of the year were introduced to reduce the threat of ships strikes of the endangered North Atlantic right whales. Established in 2008⁴¹, the measures were unpopular with some commercial shippers, who cited economic effects of added costs, increased transit times and delays of time-sensitive cargoes (World Shipping Council, 2006). Five years later, these speed restrictions are no longer actively discussed as the source of economic hardships for the industry.

Today, the shipping industry and the World Shippers Council cite their work with the International Maritime Organization (IMO) to establish Areas to Be Avoided (ATBA) and with the US Coast Guard to design traffic separation schemes to reduce the probability of vessel-whale collisions (World Shipping Council, 2013). While still not actively supporting the speed restriction measures, the Council encourages further

vessels traveling between the Mid-Atlantic ports. Therefore, their added costs would be a small fraction of the added costs for the 1,488 annual trips estimated here.

⁴¹ National Marine Fisheries Service (2008) <http://www.nmfs.noaa.gov/pr/pdfs/fr/fr73-60173.pdf>

research of technological innovations to protect the right whales, as well as improving the knowledge of their locations, so ships could avoid transiting through these areas.

The opponents of the proposed measures may also argue that we do not estimate the full economic effect of rerouting vessels from their established routes. We do not estimate the cost of potential delays and the down-the-pipe effects of, for example, having stevedores work overtime to unload a delayed vessel. However, we also do not estimate the full economic benefits of building wind projects closer to shore. The benefits of added employment, improved attractiveness of the US offshore wind market that would come from the availability of the near-shore areas and bring investment in US manufacturing, increased climate change mitigation through displaced CO₂ emissions, and benefits to national security are also not assessed due to the limited scope of the study.

Furthermore, to reduce complexity of the analysis, we assume that the proposed rerouting scenario is a zero-sum game: as WEAs are brought closer to shore, this reduces the need of building far from shore. Thus, we effectively eliminate the possibility of building wind projects in deep waters and assume that only the near-shore areas would be developed. In reality, the far-shore areas would still be open for development as technological innovations make building in those waters economically justified.

It is also important to emphasize that the largest benefits from moving WEAs closer to shore stem from the reduction in debt that developers would have to accumulate to build wind projects. The current financing rates accessible to developers are high due to the associated risk of investing in this new technology. Ensuring that government loan guarantees are available to offshore wind developers would help

reduce the risk of investing in these projects. Ultimately, it could help reduce the cost of wind-generated electricity to consumers.

We realize that government regulation of vessel traffic in the EEZ and outside the IMO-designated shipping areas is constrained compared to the territorial sea. This makes implementation and compliance challenging. However, active regulation of the vessel traffic will not be needed. Once the discussed areas are designated as wind energy areas, and once the wind projects are built, the ships will avoid these areas. Ensuring that 1) the WEAs are marked on regional navigational charts, 2) that wind project construction windows are known, 3) that the work areas are clearly visible to mariners, and 4) that a safe passing distance is observed would preserve the safety of marine operations.

Additionally, it is important to emphasize that although the CBA of the proposed rerouting of ships suggest a specific policy change, it is important to remember that were it to be implemented, other site-specific considerations (e.g., commercial fishing and wildlife habitats) would have to be assessed prior to the permitting of wind projects in any specific area within the alternative WEAs.

In the end, considering the large societal benefits, modifying areas where vessels transit between the Mid-Atlantic ports needs to be included in the portfolio of policies used to support the growth of the US offshore wind industry. The framework and the estimates here do not capture all of the details involved in estimating the full costs and benefits associated with the proposed vessel transit modifications. However, our study offers an insight into what such effects could be if such a policy were adopted. Careful planning, stakeholder engagement, and consideration of economic

effects can help build a robust offshore wind sector in the US, while ensuring the uninterrupted and safe operation of the maritime industry.

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Appendix

PUTTING FINDINGS IN CONTEXT

To illustrate how the proposed alternative would translate into the actual costs and benefits to consumers, we calculate several metrics.

6.1 The Added Cost per Metric Ton of Goods Transported

The 1,488 vessel trips that would be rerouted represent 12.5% of the total 11,923 trips by large deep-draft vessels that transited in and outside of the study area. Thus, we assume that in 2009, these 1,488 vessel trips transported 12.5% of the total 225,535,145 tons of cargo that are moved by the ships in the area in 2009 (USACE, 2009b). This amounts to 28,191,893 tons transported by the affected vessels in 2009. Thus, to determine the added cost per ton of goods transported, the total annual added cost of rerouting is divided by 28,191,893 tons (Eq. 35).

$$\text{Added cost per ton of good transported} = \frac{\text{total annual cost of rerouting/tons transported by the affected ships}}{\text{Eq. 35}}$$

6.2 Additional Wind Capacity that Could Be Built with the Benefits

To calculate the additional MW of wind capacity that could be built given amount of net societal benefits (in 2012\$) generated from the rerouting scenario analyzed we use the current capital cost of 1 MW of wind capacity in shallow waters - approximately \$6 million in 2012\$ (Levitt et al., 2011) (Eq. 36).

Added MW of wind capacity = Net benefits (in 2012\$)/capital cost of 1MW of
wind capacity (Eq. 36)

6.3 Displaced CO₂ if Additional Wind Capacity Is Built

We use the same methodology as described in Chapter 3 to estimate power output for wind projects that we assume would be built using the benefits from the proposed policy. We assume that the projects would be built in shallow water areas comparable to those found in ALT-WEAs. We assume an average Capacity Factor of 41.3%⁴², 10% wake effect losses and 95% availability. We use estimates of kg of CO₂ emitted to generate 1 kWh from coal and natural gas power plants (Energy Information Administration (EIA), 2013). Thus, 0.94 kg of CO₂ is generated per kWh of electricity from coal and 0.5 kg of CO₂ is generated from natural gas power plants. We assume that electricity generated from these wind projects would displace fossil-fuel generation when it is added to the grid. The generation that would be displaced would consist of 60% coal- and 40% natural gas-produced power (PJM, 2009) (Eq. 37, 38).

$$\begin{aligned} \text{CO}_2 \text{ displaced avoiding generation from coal plants} = \\ \text{kWh generated over 25 years} \times \text{percentage of displaced generation [60\%]} \times \\ 0.94 \text{ kg} \quad (\text{Eq. 37}) \end{aligned}$$

⁴² The average for all Alternative WEAs (Dvorak et al., 2012)

$$\text{CO}_2 \text{ displaced avoiding generation from natural gas plants} = \text{kWh generated over 25 years} \times \text{percentage of displaced generation [40\%]} \times 0.5 \text{ kg/kWh of CO}_2$$

(Eq. 38)

6.4 Reduction in the Cost of Power if the Near-Shore Wind Areas Are Developed

We calculate how the proposed policy would impact a customer's electricity bill should wind projects be constructed in ALT-WEAs rather than in the SQ-WEAs. We calculate this potential reduction in the cost per kWh, and the annual and monthly cost of electricity.

We use the amount of power that would be generated by all of the ALT-WEAs and the average annual household consumption by customers in NJ, DE, MD, and VA (EIA, 2011) - 11,676 kWh (in 2011) - we estimate that approximately 4.2 million households annually could be fully powered by electricity generated at the ALT-WEAs (Eq. 39).

$$\text{Number of households powered annually} = \frac{\text{Annual power produced from all of the ALT-WEAs}}{\text{average annual household consumption}} \quad (\text{Eq. 39})$$

Then we estimate the reduction in the annual cost of electricity for an average household (Eq. 40). We use the pre-discounted value of benefits (\$38 Billion), as the reduction in the cost of electricity would be continuous throughout the 25 years of wind project operation.

Savings for an average household = Total savings from the proposed policy/number of households that could be powered by wind power annually

(Eq. 40)