Integrated Wave and Offshore Wind Energy: Benefits and Challenges

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Writing this thesis has been an incredibly satisfying and rewarding educational experience. It has been a tremendous opportunity to work on a research project relevant to a growing, cutting-edge industry that can make major contributions to global efforts to mitigate the effects of climate change. I hope that my thesis research can contribute to this industry and to this discipline, particularly as more offshore wind farms are developed in the US and worldwide and wave energy technology continues to mature. At the very least, this research has sparked an interest in marine renewable energy that I hope to carry forward in my future endeavors.

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Abstract

Offshore wind energy and wave energy are renewable energy sources that share the same marine environment. Collocating these systems can provide technical benefits through reduced power variability and wave loading. However, the extent of these effects differs between sites and regions. The regional differences in power variability of combined offshore wind and wave energy systems is investigated. Power output of wind, wave, and combined systems is modeled for sites throughout the US East Coast, US West Coast, and North Sea in Scotland. The effects of wind and wave loading on floating offshore wind turbines are also investigated to analyze how combined systems can decrease wave loading on floating offshore wind turbines. Comparing the power variability of combined systems across the US East Coast, US West Coast, and North Sea in Scotland, indicates decreased variability of combined systems on the US West Coast and North Sea in Scotland but minimal effect on the US East Coast. Reduced power variability and wave loading can benefit combined offshore wind and wave energy systems, but these effects differ across regions.
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Chapter I. Introduction

Greenhouse gas emissions from the burning of fossil fuel energy sources contribute to global climate change (IPCC 2013). New and improved energy technologies, particularly renewable energy, enable societies to fulfill their energy needs while minimizing their environmental impacts. Implementing renewable energy technology is in line with worldwide cooperative efforts to decrease carbon dioxide emissions set forth in the United Nations Paris Agreement in 2016. Countries around the world are committed to its goal of curtailing global warming below a 2°C rise from pre-industrial temperatures (United Nations Climate Change 2015). Offshore wind energy, a renewable energy source in which wind turbines are sited at offshore coastal sites, can contribute to this environmental goal while meeting much of the world’s energy requirements. Offshore wind has the lowest lifecycle greenhouse gas emissions (GHG) rate among all conventional and renewable energy sources, even lower than onshore wind, other renewable sources, and fossil fuels such as coal, oil, or natural gas (Figure 1.1; Amponsah et al. 2014).

![Figure 1.1 Lifecycle GHG emissions estimates by energy source, from Amponsah et al. (2014)](image)
The lower GHG emissions from offshore wind compared to onshore wind is partially driven by the economy of scale of offshore wind farms, which are typically larger than onshore wind farms. Additionally, onshore wind GHG estimates factor in emissions from the clearing of forests or excavation of peat during construction, which increases emissions compared to offshore wind where this is unnecessary (Amponsah et al. 2014). The offshore wind resource is abundant in coastal regions worldwide, with an estimated global energy potential of 192,800 TWh annually in water depths up to 200 m (Arent et al. 2012). Offshore wind power potential capacity by country is shown in Figure 1.2 (Arent et al. 2012).

![Figure 1.2 Global offshore wind energy potential by country, from Arent et al. (2012)](image)

This energy potential exceeds the 2015 worldwide primary energy consumption of around 168,515 TWh (EIA 2017), and is around 8 times the 2016 worldwide electricity consumption of slightly under 25,000 TWh (Enerdata 2018). Between offshore wind’s energy abundance and low GHG emissions, it is a compelling renewable energy source that can contribute to global power capacity while decreasing anthropogenic emissions.

Another renewable energy source abundant in coastal areas is wave energy, the conversion of ocean waves into electricity. It also produces lower lifecycle GHG emissions than fossil fuel energy sources and some other renewables like onshore wind, solar, and hydropower, though further studies are needed as the technology continues to mature (Amponsah et al. 2014). Worldwide estimates of available wave power range
between 1-2 TW, and annual wave energy production using the lower 1 TW figure amounts to around 2000 TWh after factoring in the technically feasible capacity (Lynn 2014; Titah-Benbouzid and Benbouzid 2015). Though this is several orders of magnitude less than potential offshore wind energy or the 2016 global electricity demand, it is still a significant amount of energy found at collocated offshore sites. Wave energy also has a high energy density relative to other sources, due to the large wind fetch, or length of ocean over which the wind blows and creates waves. Although power density of wind-waves is small in terms of area, ranging from 0.01-0.1 W/m$^2$ compared to 350 W/m$^2$ for solar power, the fetch leads to much higher power density per meter of wave front, as high as 100 kW/m in some cases (Tavner 2017). The high energy density of waves enables significant energy production that requires relatively little physical space. Wave energy conversion techniques are still considered technologically immature, however, and require substantial government subsidy for development and testing (Titah-Benbouzid and Benbouzid 2015). Further research is required for the commercialization of wave energy conversion, but its relatively low GHG emissions, high energy density, and total energy resource make wave power a compelling renewable energy source that shares the marine environment with offshore wind.

Ongoing research efforts in both offshore wind and wave energy technology and the similar locational requirements of these marine energy systems enable synergies that can compel further offshore renewable energy technology development. Wave energy converters (WECs) may be collocated or integrated with offshore wind turbines to provide mutual advantages for both marine renewable energy systems (Perez-Collazo et al. 2014). This thesis investigates the benefits and challenges of combined offshore wind and wave energy, with particular emphasis on floating offshore wind turbines in intermediate and deeper water sites at depths of 50 m or greater. Combined wave-wind\(^1\) energy systems may provide technical benefits through more consistent power output, higher project energy yields, increased power predictability, cost-savings through shared

\(^{1}\) This thesis uses the term “wave-wind” to describe combined wave energy and offshore wind energy systems. This is to distinguish these systems from the term “wind-wave,” which is conventionally used to describe ocean waves that are produced by the local wind, as compared to swell, which are waves produced at distant locations that propagate to the site of interest.
electric grid connections and foundation substructures, and shared operations and maintenance logistics. They may also exhibit legislative benefits for both technologies through similar regulatory procedures, shared marine spatial planning, and simplified licensing (Pérez-Collazo et al. 2015).

Both offshore wind power and wave power are time-variable energy sources dependent on the wind and wave resource at any given moment at the project location. Power output can be difficult to predict accurately and total power production must be matched with electricity demand, providing challenges for energy producers and grid operators. Variable energy sources may increase grid operation costs, as the uncertainty and variability of power production requires reserve capacity of other conventional or renewable energy sources that can meet power demand, which also varies with time (Ueckerdt et al. 2015). Collocating wave energy converters with offshore wind turbines may provide a way to reduce the power output variability of both individual respective systems (Stoutenburg et al. 2010; Fusco et al. 2010). Stoutenburg et al. (2010) examined the power variability of collocated wave and wind energy along the California coast, and found that combined systems exhibit lower variability on all time-scales, including interannual, seasonal, diurnal, and hourly variability. Collocated systems decrease the number of hours of no power output from over 1000 hours for wind alone and 200 hours for wave alone to fewer than 100 hours for a combined system (Stoutenburg et al. 2010), ensuring that some power, even in minimal quantities, could be more consistently provided to the electric grid. Seasonal variability of power output could be reduced in California by taking advantage of typical wind peaks in the late spring and early summer and wave peaks in the winter, though both resources share annual lows in the late summer (Stoutenburg et al. 2010). The study found that the correlation between wind and wave resources was lower in California for collocated systems than for separate wind or wave systems located further apart, indicating the relative advantage of siting offshore wind farms and wave farms together rather than separate farms at geographically distinct sites (Stoutenburg et al. 2010). Fusco et al. (2010) emphasized the significance of the type of wave resource, either wind-waves or swells, on the power variability of a combined system in Ireland, indicating the effects of local and regional conditions on power variability of collocated systems. The west and south coasts of Ireland exhibit wave fields
dominated by swells that are not strongly correlated with local wind, allowing for reduced variability and higher predictability for a combined wave-wind energy system, whereas the east coast of Ireland is dominated by wind-waves that are strongly correlated with local winds and therefore do not significantly reduce power variability in a combined system (Fusco et al. 2010). These differences provide evidence of the potential reduction of power variability for combined offshore wind and wave energy systems, but also indicate the importance of regional and local meteorological-ocean (met-ocean) conditions to power variability.

Wave energy converters may also be used to decrease the size of incoming waves as they approach an offshore wind turbine, minimizing the wave’s impact on both floating and bottom-fixed offshore wind turbines. When a wave energy converter extracts energy from an incoming wave, it decreases the downstream significant wave height, or size of the wave (Carballo and Iglesias 2013; Veigas et al. 2014). The resulting decrease in wave size, termed the shadow effect, can be utilized in collocated wave-wind farms to induce calmer sea-states around an offshore wind farm that provide better accessibility for operations and maintenance (Perez-Collazo et al. 2014; Astariz and Iglesias 2015; Astariz et al. 2015) and to reduce wave loading on the wind turbines (Perez-Collazo et al. 2014). Rough sea conditions can prevent necessary wind farm repairs, thus extending plant downtime and increasing lost revenue, so increasing the duration of accessibility is important for operations and maintenance. Decreasing wave size with wave energy converters can benefit both bottom-fixed and floating turbines by potentially extending the amount of time that wind turbines are accessible (Astariz and Iglesias 2015). Additionally, smaller wave size may provide particular benefits for floating offshore wind turbines, which are subject to both wave and wind loading (Matha et al. 2011). Wave loading impacts the motion and stability of floating wind turbines more prominently in certain floating foundation types than others, with submerged foundations typically impacted less than surface foundations (Butterfield et al. 2005). Between platform stability and increased operations and maintenance windows, the shadow effect of collocating wave energy converters with offshore wind turbines may provide significant synergies that warrant further investigation.
This thesis examines the power output variability of wind, wave, and combined wave-wind energy systems, as well as the motion of floating offshore wind turbines due to wave and wind loading with and without collocated wave energy converters. Analysis is conducted for several regions, including the North Sea in Scotland, the United States East Coast, and the United States West Coast. What reductions in power output variability can be achieved through the integration of wave energy converters into floating offshore wind farms? What regional differences exist in this power variability between the US East Coast, West Coast, and the UK North Sea? What impact does collocating wave energy converters with offshore wind turbines have on the wave-structure interactions of floating wind turbines and their environment? Power variability is investigated through numerical modeling of power output for National Oceanic and Atmospheric Administration (NOAA) National Data Buoy Center (NDBC) sites on the US East and West coasts and the Hywind Scotland floating wind farm in Scotland. Motion of floating offshore wind turbines due to wave and wind loading is analyzed through a combination of computational fluid dynamic (CFD) modeling and theoretical analysis of wind loading on a floating wind turbine. As the first utility-scale floating wind farm in the world, Hywind Scotland provides a compelling case study for comparison to US East and West coasts sites that may be suitable for other deep-water floating wind turbine installations.
Chapter II. Background

This chapter provides background material on offshore wind and wave energy. Particular emphasis is placed on the theories governing wind and wave power, foundation types and classification of systems, and the Hywind Scotland and Pelamis Wave Energy Converter case studies.

Chapter 2.1 Offshore Wind – Overview

Offshore wind power exhibits several technical advantages over onshore wind power, including higher mean wind speeds, lower wind turbulence, large available project sites, and proximity to coastal regions with high electricity demand (Burton et al. 2011; Esteban et al. 2011). Capacity factor, or the amount of energy a turbine actually produces compared to its rated power capacity, is typically larger for offshore sites due to the higher and more consistent wind speeds at sea than on land (Burton et al. 2011). Lower wind turbulence also decreases generator fatigue, increasing the expected lifetime of offshore generators (Esteban et al. 2011).

Offshore wind continues to expand in countries like the UK, which had around 5 GW of installed offshore wind capacity in 2015 and has an expected capacity between 20-55 GW by 2050 (Rhodri and Ros 2015). Figure 2.1 (IRENA 2016b) shows the substantial increase of global offshore wind capacity from practically no offshore wind capacity in 2001 to around 12.5 GW by 2015. This growth is projected to continue to around 350 GW by 2045 (IRENA 2016b), a 2,700% increase from 2015 capacity indicating the scale of the expected growth of the offshore wind industry worldwide.

![Figure 2.1 Global installed and projected offshore wind capacity, from IRENA (2016b)](image)

Of the 2015 global 12.5 GW capacity, 11.2 GW (89.6%) were located in Europe alone across 54 offshore wind farms. 25 of these offshore wind farms were located in the UK, followed by 13 farms in Germany, 7 in Denmark, 5 in Belgium, 2 in the Netherlands, and
2 in Sweden (IRENA 2016b). There have also been significant installations in China and increasing installations in Japan, South Korea, and Taiwan. Finally, the United States constructed its first offshore wind farm in 2016 at Block Island, a 30-MW wind farm (GWEC 2016). The relative contributions to the global offshore wind capacity by each country can be seen in Figure 2.2, with the overwhelming majority of capacity spread across several European countries, led by the UK, and a sizeable capacity in China.

![Figure 2.2 2016 Global cumulative offshore wind capacity, from GWEC (2016)](image)

The US is undergoing a growing trend towards the construction of more offshore wind capacity. The US Department of Energy (DOE) and Department of the Interior have developed a strategy for the promotion of offshore wind across the US, and several states have included offshore wind specifically in their statewide renewable energy plans, including Maryland and New York (Gilman et al. 2016; NYSERDA 2017). New York has committed to the construction of 2.4 GW of offshore wind capacity by 2030, and has leased offshore sites to project developers in addition to investigating further potential sites for development (NYSERDA 2017). Other states, including New Jersey and Maryland, have also set significant offshore wind capacity targets, while California and Hawaii are investigating potentially suitable sites for floating offshore wind (Drouin 2018). The US offshore wind market is currently led by the East Coast, with many states...
setting ambitious offshore wind capacity goals and leasing coastal sites for development. These states include Maryland, Massachusetts, New York, New Jersey, North Carolina, Rhode Island, South Carolina, and Virginia, as well as early assessments in Georgia and floating foundation research in Maine. On the West Coast, California and Oregon are reviewing potential ways of bolstering the offshore wind market and Hawaii has received several lease requests for offshore wind development. Even Ohio, a non-coastal state, is pursuing offshore wind in Lake Erie with the Icebreaker Wind project (Business Network for Offshore Wind 2017). These existing and planned projects only begin to tap into the United States’ estimated 10,800 GW (10.8 TW) of gross power capacity or 2,058 GW (2.058 TW) of technical power capacity, which factors in the estimated net capacity factor of sites. The regional breakdown of the US offshore wind resource is shown in Figure 2.3 (Gilman et al. 2016).

Figure 2.3 Available US gross and technical offshore wind capacity, from Gilman et al. (2016). The map shows the capacity factor used to determine technical power capacity in each region.
Utilizing these offshore wind resources, however, also presents several challenges. Offshore wind costs are currently higher than onshore wind costs, largely due to greater engineering, construction, and operations costs at sea (Esteban et al. 2011). Figure 2.4 shows the projected reduction of the levelized cost of energy (LCOE) of US offshore wind from around $200/MWh in 2015 to less than $100/MWh by 2030, though cost can also vary significantly between sites (Gilman et al. 2016). This represents a projected 50% reduction of US offshore wind cost by 2030.

![Figure 2.4 Unsubsidized levelized cost of energy (LCOE) for US offshore wind, from Gilman et al. (2016). Originally from Beiter et al. (2016)](image)

The LCOE is a useful metric for comparing the long-term cost of energy, as it takes into account both capital and operating costs over an assumed project lifetime (EIA 2018). Estimates for LCOE can vary greatly based on the design assumptions and financial assumptions like the discount rate, as well as on the project site and conditions. Esteban et al. (2011) estimated a LCOE of $120/MWh for offshore wind, compared to a lower LCOE of $60-90/MWh for onshore wind, $40-80/MWh for large hydropower, $30-74/MWh for nuclear, and $51.3/MWh for integrated gasification combined cycle, and a higher LCOE of $180-230/MWh for photovoltaic solar. However, these LCOE values can change significantly over a relatively short span of time. For example, the LCOE of photovoltaic solar, reported as higher than offshore wind in 2011 by Esteban et al. (2011), decreased in the US to between $40-60/MWh by 2017 (Fu et al. 2017). Thus, the
cost of energy is highly variable over short time periods, and projections of offshore wind
cost reductions may be realized as the industry continues to grow.

There are also technical challenges associated with offshore wind. Lower ocean
surface roughness and wind turbulence compared to onshore sites can lead to greater
turbine wake effects (Esteban et al. 2011), potentially affecting the capacity factor and
loading of downstream turbines. The large available project areas in the ocean, however,
help to overcome this, as turbines can be spaced sufficiently to reduce wake effects.
Additionally, offshore wind turbine technology is typically adapted from existing onshore
wind turbine technology, but must endure greater loading and corrosion in the marine
environment, thus prompting further research into offshore-specific designs (Esteban et
al. 2011).

**Chapter 2.1.1 Offshore Wind – Theory**

Wind power is governed by the following two equations. Equation (2.1) is
adapted from Burton et al. (2010), Engineering Toolbox (n.d.i), and Jain (2011):

\[
\frac{P_{\text{wind,potential}}}{\rho} = \frac{1}{2} \rho \frac{A}{\rho} v^3
\]  

(2.1)

where \( P_{\text{wind,potential}} \) is the available wind power (W), \( \rho \) is the air density (kg/m\(^3\)), \( A \) is
the rotor swept area perpendicular to the incoming wind (m\(^2\)), and \( v \) is the wind velocity
at hub height (m/s). Factoring in the efficiency of the turbine \( \zeta \), commonly called the
power coefficient, yields the wind power actually produced by a wind turbine:

\[
P_{\text{wind}} = \frac{1}{2} \zeta \rho A v^3
\]  

(2.2)

The Betz limit states that the theoretical maximum turbine efficiency \( \zeta \) is 0.593 (Burton
et al. 2011), but in practice efficiency between 0.45-0.5 is more typical under idealized
conditions (Department of Environment, Climate Change and Water NSW 2010). The
real field efficiency is even lower, however, and varies with wind speed. Rearranging
Equation 2.2 provides an expression for a specific turbine’s efficiency \( \zeta \) in terms of its
rated power capacity \( P_{\text{nominal}} \), air density \( \rho \), rotor swept area \( A \), and nominal wind
speed \( v_{\text{nominal}} \):
\[ \xi = \frac{2P_{\text{nominal}}}{\rho A v_{\text{nominal}}^3} \]  

(2.3)

The calculated turbine efficiency can then be used to determine the actual power production of a wind turbine using Equation 2.2.

**Chapter 2.1.2 Offshore Wind – Foundations**

Offshore wind foundations are typically classified as bottom-fixed structures or floating structures. Bottom-fixed turbines have foundations mounted to the ocean floor and floating turbines have foundations that float on the ocean surface while tethered to the sea bed (EWEA 2013). Figures 2.5 from EWEA (2013) provide a graphic summary of bottom-fixed foundation types for offshore wind turbines.

![Figure 2.5 Bottom-fixed foundation types, from EWEA (2013)](image)

Among bottom-fixed structures applicable in shallower depths of 0-50 m, monopiles are the most common foundation type, followed by gravity-based structures and then space frame structures (EWEA 2013). Monopiles are large-diameter cylindrical steel piles that are driven or drilled into the seabed floor (IRENA 2016b). They are typically used in shallow water depths up to 30 m (EWEA 2013; Keivanpour et al. 2017). Next, gravity-based structures consist of a large reinforced concrete base that supports the weight of the rest of the turbine foundation and the turbine itself. These foundations are primarily used in very shallow water of depths less than 10 m (EWEA 2013; Keivanpour et al. 2017), though they may also be used to support larger turbines in slightly deeper water when
monopiles are not feasible because of the ground conditions (IRENA 2016b). Finally, space frame structures consist of welded steel designs that are used for larger turbines in deeper water, typically in the mid-depth range of 20-50 m (EW EA 2013; Keivanpour et al. 2017). Common designs include the jacket foundation, tripod, and tripile, though tripods and tripiles are experimental designs that are currently considered too costly for industrial implementation (IRENA 2016b). Figure 2.6 shows two jacket foundations at the harbor in Peterhead, Scotland before transportation to their offshore construction site elsewhere.

![Figure 2.6](image)

*Figure 2.6 Jacket foundations pre-installation. Peterhead, Scotland. Photo taken by Roan Gideon*

Siting offshore wind turbines at depths of 60 m or greater requires floating wind turbines. These higher depth sites comprise an estimated 80% (4,000 GW) of offshore wind resources in Europe, 60% (2,450 GW) in the US, and 80% (500 GW) in Japan (Rhodri and Ros 2015). Figure 2.7 (Hartman 2016) shows the breakdown of technical energy potential in the US for depths greater than 60 m that require floating foundations and less than 60 m that may still use bottom-fixed foundations.
The high proportion of offshore wind energy accessible only at these deep-water sites illustrates the significant opportunity floating offshore wind turbines present for countries to expand their offshore wind resource potential and increase the achievable capacity of offshore wind.

There are several existing concepts for floating offshore wind foundation types. These can be broadly categorized as spar-buoy, tension leg platform (TLP), and semi-submersible designs, though there are also other variations of these designs (Leung and Yang 2012; EWEA 2013; IRENA 2016a).

*Figure 2.7 Available US technical offshore wind power by state and depth classification, from Hartman (2016)*

*Figure 2.8 Bottom-fixed and floating foundation types with applicable depth range and power rating, from EWEA (2013)*
The spar-buoy concept shown in Figure 2.8 consists of a submerged cylindrical buoy ballasted towards its bottom to keep its center of gravity lower than its center of buoyancy, and is used at the Hywind Scotland site (EWEA 2013). Ballasting to maintain a lower center of gravity than center of buoyancy enables static stability for small angular displacements, otherwise the slender tower might tip over. Unlike ship hulls which are designed with a lower center of buoyancy that shifts laterally if the ship rotates to provide a restoring moment (Springer 2016), the spar-buoy center of buoyancy does not move significantly. This enables the buoyant and gravitational forces to work in tandem to restore the turbine to its upright position when it begins to pitch. Catenary or taut mooring lines are also attached to drag or suction anchors on the sea floor to keep the foundation in place (IRENA 2016a). The spar-buoy was first ocean-tested in 2009 in Norway at a 2.3-MW pilot project and separately in 2013 in Japan at a 2-MW hybrid spar pilot project (IRENA 2016a), before its 2017 implementation in the five-turbine, 30-MW Hywind Scotland project. There are several advantages of the spar-buoy concept, including lower wave-induced motions, a relatively simple design, and a lower mooring cost, although the spar-buoy also requires deeper waters of at least 100-120 m and heavy-lift vessels for offshore installation (IRENA 2016a; EWEA 2013). Leung and Yang (2012) cite that ballast-stabilized concepts like the spar-buoy are applicable for depths between 200-700m, making it a potential foundation type for sites with much greater depths. This minimum depth requirement does, however, prohibit its application from intermediate depths, decreasing its versatility as a foundation for other, shallower depth sites. The Hywind Scotland spar-buoy project developed by Statoil is the first commercial-scale installation of a floating offshore wind farm, commissioned in 2017 and building off the success of the Hywind Pilot Project constructed in 2009 in Norway (Statoil n.d.b). The spar-buoy’s implementation at Hywind Scotland makes it a compelling technology for further study, and is used for wind and wave loadings analysis in this thesis.

A second concept, the tension leg platform (TLP), consists of a semi-submerged buoyant structure attached to the seabed with tensioned mooring lines (EWEA 2013). The mooring lines are attached to suction or piled anchors on the seabed and arms that protrude vertically from the platform foundation (IRENA 2016a; Figure 2.8). The TLP
concept was demonstrated in 2016 by GICON in a 2.3-MW pilot in Germany (IRENA 2016a). Its advantages include lower wave-induced motions, lower mass, the possibility of onshore assembly, and a lower allowable depth between 50-60 m. However, the TLP also has a higher mooring cost compared to other floating foundations, it may be difficult to keep the platform stable during transportation and installation, specifically-designed vessels may be required for installation, and the effects of high-frequency waves on the structure are still uncertain (IRENA 2016a).

The third major floating foundation concept is the semi-submersible foundation, which consists of a buoyancy-stabilized structure that floats on the surface with several submerged vertical columns connected by bracings or pontoons (IRENA 2016a; Leung and Yang 2012; Figure 2.8). The semi-submersible structure is anchored to the seabed using either catenary or taut mooring lines connected to drag anchors (IRENA 2016a). The concept was ocean tested in 2011 by Principle Power / WindFloat in a 2-MW pilot in Portugal, and in 2013 by Fukushima FORWARD in a 2-MW pilot in Japan and again in 2015 in a 7-MW pilot in Japan (IRENA 2016a). The semi-submersible concept can be installed in a much lower water depth of 40 m (IRENA 2016a), making it more versatile for application at a broader range of sites. It also can be constructed onshore, can be transported using conventional tug boats with a platform draft of around 10 m that enables shallow water port access, and has a lower mooring cost than other floating foundation concepts. However, the semi-submersible concept is located at the water surface, making it more susceptible to wave-induced motion. It also has a more complex manufacturing process, uses more material, and consists of a larger structure than some of the other floating foundation concepts (IRENA 2016a).

There are many versions of these designs based on these three general concepts, with several companies designing demonstration plants of their own floating foundations. These include Japan Marine United producing a spar-buoy concept demonstrated in 2013 in Japan and again in 2016 in a 5-MW pilot. Glosten Associations / PelaStar is developing a 6-MW pilot of its tension leg platform foundation. Ideol / Floatgen developed a 2-MW pilot of a semi-submersible foundation in France in 2017, and Hexicon has scheduled a pilot project of two 5-MW turbines mounted on a single semi-submersible platform in the UK in 2018 (IRENA 2016a). There is a significant amount of
private-company research and development of floating wind foundation concepts, coupled with research by government organizations like the US National Renewable Energy Lab (NREL) and universities like the Massachusetts Institute of Technology (MIT) (Leung and Yang 2012), among others.

Chapter 2.1.3 Offshore Wind – Floating Foundation Motion

The freedom of motion of a floating wind turbine foundation presents unique challenges compared to bottom-fixed foundations. Floating structures are subject to three possible translational motions, namely vertical heave, lateral sway, and longitudinal surge, and three possible rotational motions, namely yaw about the vertical axis, pitch about the lateral axis, and roll about the longitudinal axis, for a total of six possible types of motion shown in Figure 2.9 (Tran and Kim 2015).

Floating wind turbines are subject to many environmental forces that can induce these types of motions, including wind and wave loading. Of primary interest in this thesis are the environmental forces from wind and waves, as well as the gravitational and buoyant forces that contribute to the foundation stability of a spar-buoy.

The spar-buoy, tension leg platform, and semi-submersible floating foundation concepts are subject to different relative impacts from wind and wave loading, leading to different typical turbine motions based on the structural design of the foundation type. In general, submerged foundations like the spar-buoy are subject to less wave loading than surface-floating foundations like the semi-submersible or tension leg platform.
(Butterfield et al. 2005). The tension leg platform is actually considered the most stable, however, due to its taut mooring lines that add structural stability, whereas the semi-submersible concept is the most susceptible to wave-induced motions (Butterfield et al. 2005). The spar-buoy, which is one of the heavier designs (Butterfield et al. 2005) and penetrates the deepest into the water, experiences relatively low impact by waves but exhibits significant pitching due to wind loading (Hersleth 2018). A study of a spar-buoy foundation with an NREL 5 MW turbine found pitch angle motions of up to 8° for typical production wind speeds and 14° for extreme wind speeds, potentially placing the wind turbine in its own turbulent wake (Matha et al. 2011). Floating turbines may also exhibit yaw rotation due to wind loading depending on the foundation type (Matha et al. 2011). These pitching and yawing rotations can temporarily place the wind turbine in a turbulent zone that decreases the turbine’s performance, as shown in Figure 2.10 (Tran and Kim 2015).

The turbine may enter its own turbulent wake as it pitches back and forth due to varying wind speed, which can decrease the capacity factor and mechanically stress the turbine and generator. This pitching effect can be observed at the Hywind Scotland project site in Figure 2.11.
Chapter 2.1.4 Offshore Wind – Hywind Scotland

Hywind Scotland is a 30-MW floating offshore wind project developed by Statoil and jointly owned by Statoil and Masdar (4C Offshore n.d.). It is the first commercial-scale floating offshore wind farm in the world, located approximately 35 km off the east coast of Peterhead, Scotland at the Buchan Deep site in the North Sea, in water depths between 95-120 m (Statoil n.d.c).

The project builds upon the spar-buoy concept developed by Statoil in 2001 and tested in a demonstration project in the North Sea in 2009 (Rummelhoff and Bull 2015). Hywind Scotland consists of 5 Siemens SWT-6.0-154 6 MW turbines for a total wind farm capacity of 30 MW, capable of providing electricity to an estimated 20,000 households (Statoil n.d.a; 4C Offshore n.d.).
In its first few months of operation since its October 2017 commissioning, the offshore wind farm has achieved a capacity factor of around 65% (Statoil 2018b; Klippenstein 2018). This is higher than the typical offshore wind capacity factor of 45-60% seen at most bottom-fixed offshore wind farms (Statoil 2018b), and significantly higher than typical US onshore wind capacity factors of around 37% (Klippenstein 2018). This especially high capacity factor can be partially attributed to Hywind Scotland’s deeper-water, further offshore site, as well as proper selection of a site with favorable wind conditions, though it is also likely skewed towards a higher capacity factor due to typically faster wind speeds in the 4 winter months over which this figure was calculated (Hersleth 2018). Still, the observed capacity factor of 65% is significantly higher than the 2017 maximum onshore wind capacity factor in the US of 44.9% in April 2017 (EIA 2018a), indicating early success of the floating offshore wind project and the promising potential of floating offshore wind at deeper sites.

The project is supported by several offices around the UK and Norway, including an operations office in Peterhead, Scotland, a control room in Great Yarmouth, England, financial services in London, and research and development in Norway (Hersleth 2018). A significant amount of monitoring and operations throughout the year can be conducted remotely from the Great Yarmouth office, including video camera monitoring and data collection of wind speed, wind direction, wave height, wave direction, wave period, turbine pitching angle, and wind power production. Turbine blade pitching, which
contributes to both power output optimization and foundation stability during extreme weather events, can also be controlled remotely from the Great Yarmouth office and other locations by the Plant Manager Halvor Hersleth (Hersleth 2018). The Hywind Scotland project has already survived both Hurricane Ophelia in October 2017 and Storm Caroline in December 2017, with wind gusts of 125 km/h (34.7 m/s, 78 mph) and 160 km/h (44.4 m/s, 99 mph) respectively and wave heights up to 8.2 m during Storm Caroline (Statoil 2018b). The wind farm even produced power during parts of these storms when the wind speed did not exceed the cut-out turbine speed of 25 m/s (Hersleth 2018). Both during extreme weather and in calmer conditions, the Hywind Scotland spar-buoy foundations and turbines are more impacted by wind loading at the hub height than by wave loading. This is due to the heavy, deep sea foundation (Hersleth 2018), which has a total weight of around 12,000 metric tons, tower diameter of 14 m, submerged height of around 78 m, and hub height of 98.6 m (Statoil n.d.a, 4C Offshore n.d.; Statoil 2018a).

In addition to remote monitoring, the Hywind Scotland site must be accessible for repairs for annual maintenance and when turbines malfunction. Annual maintenance will occur each summer for 3-4 days per turbine. Maintenance is conducted during the summer when there is typically less power, so there will be fewer losses due to turbine downtime, and the calmer ocean weather allows for easier access during the summer with about 90% confidence (Hersleth 2018). Offshore visits are serviced by a ship specific to the Hywind Scotland project that is docked at a Hywind Scotland berth in the Peterhead port (Hersleth 2018).

![Figure 2.14 Hywind Scotland ship and berth. Photos taken by Roan Gideon.](image)
Chapter 2.2 Wave Energy – Overview

Wave energy converters extract energy from ocean waves and convert it into electricity (Titah-Benbouzid and Benbouzid 2015). There are many different types of marine energy devices that utilize the energy of moving water in the ocean, such as wave energy and tidal energy (Lynn 2014). This thesis focuses on wave energy conversion from local wind-waves produced by winds interacting with the ocean surface and from swells that are produced by deep water storms that induce waves that travel far distances without significant energy loss (Lynn 2014). Wave energy converters are categorized by their location in the ocean and by their conversion mechanism. Offshore devices operate in deep water at depths greater than 40 m, nearshore devices operate in shallow water between 10-25 m, and shoreline devices are installed on coastal land (Lynn 2014; Titah-Benbouzid and Benbouzid 2015). Though no WEC technology has yet proven dominant with regards to conversion efficiency, durability, or project economics, many different devices have been developed that belong to the general categories of attenuators, point absorbers, oscillating wave surge converters, oscillating water columns, overtopping devices, and submerged pressure differential devices (Titah-Benbouzid and Benbouzid 2015), discussed further in Chapter 2.2.2. There is a significant amount of uncertainty about the global wave energy resource, in part due to uncertainty about wave energy converter efficiency, device type, and technologically feasible project sites. Titah-Benbouzid and Benbouzid (2015) estimate a minimum 1 TW of global wave power resources, amounting to around 2000 TWh of technically achievable energy production each year, while the IPCC estimated a theoretical potential of around 29,500 TWh each year in 2012, but only 146 TWh, or 500 GW capacity, of technically achievable wave energy in 2007 (Kempener and Neumann 2014). Though there is considerable variability in estimates of the global wave energy resource, power density per meter of wave front is well-characterized. Global estimates of annual mean wave power indicate the highest wave power availability in the mid-latitudes of both the Northern and Southern Hemisphere, between 40° and 60°.
Wave power is densest worldwide in the southern Indian Ocean near the coasts of Australia, New Zealand, and South Africa, exceeding 120 kW/m in some locations. In the Northern Hemisphere, it is densest in the Pacific Ocean near the west coast of the US and Canada, varying between 20-60 kW/m, and in the Atlantic Ocean near Greenland, Iceland, and the west coast of the UK and Ireland, varying between 20-80 kW/m (López et al. 2013). Based on the geographic distribution of the wave energy resource, it is logical that 2013 wave power capacity was led by the UK with 3.8 MW and Australia with 1 MW, followed by minor installations in Portugal, Spain, Norway, Sweden, China, Italy, and the US (Kempener and Neumann 2014). Comparing this to the offshore wind energy potential by country in Figure 1.1, there are striking geographic similarities between offshore wind and wave energy resources in countries like Australia, the United States, the United Kingdom, Canada, Chile, South Africa, and other parts of western Europe and South America. This is not surprising since locally strong winds generate higher waves, and indicates the potential for regions and sites that are particularly suitable for both marine renewable energy sources.
Chapter 2.2.1 Wave Energy – Theory

Wave energy converters generate electricity using the energy stored in wind-waves and swells. Wind-waves form as wind blows over the ocean surface, inducing frictional interactions that form waves (McCormick 1981). Wind-waves are an appealing form of wave for wave energy conversion because of their predictability and energy density. Swells are packets of deep water wind-waves that form initially as wind-waves, but persist when the wind dies down and propagate over far distances with little energy loss (McCormick 1981). Unlike wind-waves, swells are not in equilibrium with local winds, and therefore are not correlated with the local wind conditions. This makes swells an attractive form of wave energy, particularly for combined wave-wind systems.

The two primary measurable properties of a wave are the significant wave height and the wave period, which can be used to estimate wave power (McCormick 1981). Waves can be modeled with both linear and non-linear wave theory, which have different applications and advantages depending on the type of wave formation and propagation (McCormick 1981). This thesis focuses on waves that exhibit behavior according to linear wave theory, as is done by Fusco et al. (2010). Linear wave theory relies on the assumption of wave height $H$ much smaller than the wavelength $\lambda$, specifically with a ratio of $\frac{H}{\lambda} \leq \frac{1}{50}$ (McCormick 1981). This defines swells caused by wind-waves well, particularly at deep water locations. The linear wave theory approximates waves using a sinusoidal profile, compared to nonlinear wave theory which predicts narrower wave crests and wider wave troughs more typical of shallow water waves (McCormick 1981). Linear wave theory models wave power with the equation:

$$P_{\text{wave}} = \frac{\rho_w g^2 H^2 T}{32\pi}$$  \hspace{1cm} (2.4)

where $P_{\text{wave}}$ is the available wave power per meter of wave front (W/m), $\rho_w$ is the density of seawater (kg/m$^3$), $g$ is the gravitational acceleration (9.81 m/s$^2$), $H$ is the significant wave height (m), and $T$ is the dominant wave period (s) (Fusco et al. 2010). Equation 2.4 predicts the available wave power per meter of wave front $b$, or if $b$ is known it can be used to predict the total available wave power for a certain length of a wave. This can be
converted to the actual power production of a wave energy converter in Watts if the operating specifications of the WEC are known for various sea-states.

**Chapter 2.2.2 Wave Energy – Devices**

There are many different types of wave energy converters, classified by both location and conversion mechanism. Wave energy converters can be classified as offshore, nearshore, or onshore devices depending on the applicable water depth, as shown in Figure 2.15 (Titah-Benbouzid and Benbouzid 2015).

![Wave energy converter location classification, from Titah-Benbouzid and Benbouzid (2015)](image)

Most types of wave energy converters fit into one of six main conversion categories, namely attenuators, point absorbers, oscillating wave surge converters, oscillating water columns, overtopping devices, and submerged pressure differential devices (Lynn 2014; Titah-Benbouzid and Benbouzid 2015; Tavner 2017). Attenuator WECs are long devices that float parallel to the direction of the waves, typically comprised of several sections that bend as a wave passes through it and extract wave energy in the process, causing progressive attenuation, or reduction in wave height (Lynn 2014). The Pelamis WEC studied in this thesis is a surface attenuator developed by Pelamis Wave Power in 1998 in the UK (Titah-Benbouzid and Benbouzid 2015; Tavner 2017).

Point absorbers are moored floating devices that are small compared to a wave’s wavelength, and extract energy from all directions of the wave through movement relative to a fixed base. Oscillating wave surge converters extract energy from the wave surge through the movement of a pendulum arm mounted to a fixed joint. Oscillating
water column devices use the compression of air in a chamber exposed on one side to the waterline to turn an air turbine inside the device, thus producing electricity by indirect use of the passing wave. Overtopping devices create structures that impound water in a reservoir above the mean sea level as a wave breaks over the device; the impounded water then passes through a hydroelectric turbine before returning to the sea level. Finally, submerged pressure differential devices are attached to the seabed floor and utilize the wave’s heave above the device to pump fluid through the device or directly drive a generator (Lynn 2014; Tavner 2017).

Figure 2.17 Wave energy converter types, from Titah-Benbouzid and Benbouzid (2015). The image is modified to correct an original mislabeling of device types that switched the “Oscillating Water Column” and “Overtopping” device labels.

These are the primary types of wave energy converter devices under development, though other concepts exist and there are many variations of these general categories. WEC devices have been tested in over 100 pilot and demonstration projects worldwide, with 53% of device concepts considered point absorbers that extract energy from the up and down heave of a wave, 33% considered terminators that extract energy from the front and back surge of a wave, and 14% considered attenuators that extract energy from the pitch rotation of a wave (Kempener and Neumann 2014). While there are many different
types of WECs under development, this thesis selects the Pelamis WEC for further analysis because of its well-documented performance and use in previous studies.

**Chapter 2.2.3 Wave Energy – Pelamis**

The Pelamis wave energy converter is an offshore attenuator device developed by Pelamis Wave Power in the UK in 1998 (Tavner 2017). The 750-kW device consists of semi-submerged cylindrical joints oriented parallel to the direction of the wave. As a wave passes through the length of the device, the segments bend at the joints. This bending motion is resisted by hydraulic rams within the device that pump pressurized fluid through internal motors. These hydraulic motors are connected to electric generators, producing electricity that is transmitted through a transformer and through an electric wire connected to the seabed (Pelamis Wave Power).

![Figure 2.18 Pelamis wave energy converter prototype and Pelamis farm visualization, from Previsic et al. (2004)](image)

The separate segments of the Pelamis WEC can be seen in Figure 2.18 (Previsic et al. 2004), as well as their orientation parallel to the direction of wave propagation, or perpendicular to the wave front itself. The Pelamis wave energy converter is selected for this study because of its well-documented power performance in many sea-state conditions of wave height and period, and its use in prior wave energy and combined wave-wind energy studies by Previsic et al. (2004), Stoutenburg et al. (2010), and Fusco et al. (2010). The use of this device for wave energy power estimates in this thesis enables more streamlined comparison to other studies of combined wave-wind power.
Chapter III. Methods

Chapter 3.1 Data Sources

Wind and wave data were required for the production of wind power, wave power, and combined wave-wind power prediction models. The primary component of necessary wind data was wind speed, which is typically recorded at lower heights than is needed for wind energy calculations. The wind speed was extrapolated to the turbine hub height for use in the power output model when it was recorded at lower heights. Wind speed data from the Hywind Scotland site was recorded at the turbine hub height and did not need to be extrapolated. Wind speed was used directly in the wind energy calculation. Wind direction was not needed for the power output modeling as turbines can typically adjust their orientation to face incoming wind. Note that wind speed anemometer measurements at hub height are typically recorded behind the turbine, decreasing the measured wind speed due to the wake effect. This was likely the case at Hywind Scotland, which would yield slightly underestimated power outputs.

The primary components of required wave data were the significant wave height and dominant wave period. The significant wave height is the average of the highest one-third of wave heights observed at a particular site during a set time period, in this case 20 minutes (NDBC 2018). The dominant wave period is defined as the wave period with the maximum wave energy (NBDC 2018). The significant wave height gives a physical representation of the amount of energy stored in a wave, while the dominant wave period represents the typical temporal spacing between waves.

The United States National Oceanic and Atmospheric Administration (NOAA) records wind and wave data through the National Data Buoy Center (NDBC) using its global network of met-ocean data-monitoring buoys (NOAA 2017). The stations record different sets of data depending on the buoy location, including the required variables of wind speed (WSPD, m/s), wave height (WVHT, m), and dominant wave period (DPD, s). Nine sites on the US East Coast and eight sites on the US West Coast were examined in this thesis. Sites considered had a minimum depth of 35 m, slightly below the required depth for floating offshore wind turbines of 50 m. This depth requirement was selected instead of 50 m because it included more sites with longer periods of data collection.
Additionally, these are significant depths at which waves are not expected to interact with the sea floor. Thus, data at 35 m of depth are adequately representative of data at 50 m.

West Coast sites included only those sites considered by Stoutenburg et al. (2010), though some sites analyzed in their study were not included in this thesis due to current unavailability of data records. All sites considered included data from 2005-2017, but analysis for each site was restricted to a continuous data range between 2-9 years, as shown in Table 3.1.

<table>
<thead>
<tr>
<th>Region</th>
<th>Station Number</th>
<th>Approximate Location</th>
<th>Depth (m)</th>
<th>Continuous years analyzed</th>
<th>Number of years</th>
</tr>
</thead>
<tbody>
<tr>
<td>US East Coast</td>
<td>41004</td>
<td>Charleston, SC</td>
<td>38.4</td>
<td>2008-2012</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>41009</td>
<td>Cape Canaveral, FL</td>
<td>40</td>
<td>2006-2012</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>44009</td>
<td>Cape May, NJ</td>
<td>43</td>
<td>2005-2009</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>44017</td>
<td>Montauk Point, NY</td>
<td>47.9</td>
<td>2005-2010</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>41025</td>
<td>Diamond Shoals, NC</td>
<td>64</td>
<td>2006-2009</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>44008</td>
<td>Nantucket, CT</td>
<td>74.7</td>
<td>2008-2010</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>44066</td>
<td>Long Beach, NJ</td>
<td>78</td>
<td>2013-2015</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>44018</td>
<td>Provincetown, MA</td>
<td>217</td>
<td>2006-2012</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>44024</td>
<td>Northeast Channel</td>
<td>225</td>
<td>2011-2014</td>
<td>3</td>
</tr>
<tr>
<td>US West Coast</td>
<td>46027</td>
<td>Crescent City, CA</td>
<td>46</td>
<td>2009-2014</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>46013</td>
<td>San Francisco, CA</td>
<td>122.5</td>
<td>2005-2011</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>46014</td>
<td>Point Arena, CA</td>
<td>256</td>
<td>2007-2011</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>46022</td>
<td>Eureka, CA</td>
<td>391.4</td>
<td>2005-2010</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>46011</td>
<td>Point Arguello, CA</td>
<td>464.8</td>
<td>2006-2010</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>46054</td>
<td>Santa Barbara, CA</td>
<td>469.4</td>
<td>2006-2014</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>46028</td>
<td>Morro Bay, CA</td>
<td>1036</td>
<td>2008-2014</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>46042</td>
<td>Monterey, CA</td>
<td>1645.9</td>
<td>2005-2014</td>
<td>9</td>
</tr>
<tr>
<td>Scotland North Sea</td>
<td>HSY2</td>
<td>Peterhead, Scotland, UK</td>
<td>120</td>
<td>December 13, 2017-February 13, 2018</td>
<td>2 months</td>
</tr>
<tr>
<td></td>
<td>HSY4</td>
<td>Peterhead, Scotland, UK</td>
<td>120</td>
<td>December 13, 2017-February 13, 2018</td>
<td>2 months</td>
</tr>
</tbody>
</table>

Most NOAA buoys provided historical data on an hourly basis, though some stations recorded data on a slightly higher time resolution of 30 minutes or less. Power output was calculated for the highest resolution time-scale for each data set, and the hourly average power output was determined to standardize the time-scale across sites. For sites with hourly historical data this was simply the calculated power production for the entire data
set, but for sites with data every 30 minutes or less for all or part of the historical record this was the hourly average of the calculated power production at the higher resolution time-scale.

Hywind Scotland site data was provided by Statoil, including high resolution wind speed for two turbines, HSY2 and HSY4, measured approximately every second, and 20-minute average significant wave height and dominant wave period. The data was collected during the wind farm’s early operational period of mid-December 2017 through mid-February 2018. The two turbines exhibited slightly different wind speeds each second, which can partially be attributed to wake effects of the upstream turbine on the downstream turbine (Hersleth 2018) and to extremely local wind fields at the site. The data was analyzed for the entire site rather than for individual turbines; the generalized Hywind Scotland site wind speed was calculated as the average of HSY2 and HSY4 wind speeds for each data observation, with only one turbine used if the other turbine did not have data for that time stamp. To more efficiently calculate wind and wave power for the Hywind site, the hourly average of wind speed, significant wave height, and dominant wave period was determined before the power was computed. This enabled greater computational efficiency of the model for the large, high-resolution Hywind Scotland data set.
Chapter 3.2 Numerical Power Models

Numerical power models predicted wind and wave power production for NOAA and Hywind sites using met-ocean data of wind speed, significant wave height, and dominant wave period. Modeling was conducted in R using programs written by the author.

Chapter 3.2.1 Wind Power Model

The wind power model predicted wind power output for NOAA NDBC and Hywind Scotland sites. The model was based on the Siemens SWT-6.0-154 turbine used in the Hywind Scotland project (4C Offshore n.d.). While different turbines may be used at different project sites, the model used the SWT-6.0-154 because of its relevance to the Hywind Scotland project. This allowed for standardization of wind power results for different sites in the UK and US, though in reality different turbine models and capacities would be used at these geographically distinct sites. This would yield different power output results from those discussed in this thesis, but the capacity factor values and shapes of power distributions should be very similar regardless of the turbine used. Some turbines are more suitable for particular sites and wind speeds than others, so the wind power model is affected by the operational wind speed range for the SWT-6.0-154 turbine. Modeling power output with another turbine would yield slightly different but similar results.

No published power curves were available from Siemens, but the SWT-6.0-154 power curve was reproduced using the turbine dimensions and operating conditions. The SWT-6.0-154 was designed specifically for offshore applications and has a 6 MW capacity. It is a 3-bladed, horizontal axis turbine with 75 m blades, a rotor diameter of 154 m, and a swept area of 18,600 m². The turbine has a cut-in wind speed \( v_{\text{in}} \), the speed at which the turbine begins to produce power, between 3-5 m/s, which was averaged to 4 m/s in the power model. It has a nominal wind speed \( v_{\text{nominal}} \), which is the lowest speed at which the turbine produces its rated capacity of 6 MW, between 12-14 m/s, averaged to 13 m/s in the model. It also has a cut-out wind speed \( v_{\text{outs}} \), the speed above which the turbine stops producing power, of 25 m/s (Siemens AG 2016).
Turbine efficiency was calculated using Equation 2.3, reproduced below. This calculation assumed an air density $\rho_{\text{air}} = 1.184 \text{ kg/m}^3$ at 25° C (Engineering Toolbox n.d.b).

$$\xi = \frac{2P_{\text{nominal}}}{\rho A v_{\text{nominal}}^3}$$  \hspace{1cm} (2.3)$$

$$\xi = \frac{2 \times 6,000,000 \text{ W}}{(1.184 \text{ kg/m}^3 \times 18,600 \text{ m}^2 \times (13 \text{ m/s})^3)}$$

$$\xi = 0.248$$

Using this calculated efficiency of $\xi = 0.248$ (although the efficiency actually varies with wind speed), the cut-in wind speed $v_{\text{in}} = 4 \text{ m/s}$, the nominal wind speed $v_{\text{nominal}} = 13 \text{ m/s}$, the cut-out wind speed of $v_{\text{out}} = 25 \text{ m/s}$, and Equation 2.2 reproduced below, power output was calculated for a range of hub height wind speeds for the SWT-6.0-154.

$$P_{\text{wind}} = \frac{1}{2} \xi \rho A v^3$$ \hspace{1cm} (2.2)$$

This produced the SWT-6.0-154 power curve shown in Figure 3.2.

![SWT-6.0-154 Power Curve](image)

**Figure 3.2 SWT-6.0-154 Power Curve**

The turbine begins to produce power at the cut-in wind speed $v_{\text{in}}$ of 4 m/s. Between 4 m/s and the nominal wind speed $v_{\text{nominal}}$ of 13 m/s, the power curve follows a cubic relationship with wind speed. The cubic profile ends here, however, and flat-lines between 13 m/s and the cut-out wind speed $v_{\text{out}}$ of 25 m/s as the turbine continues to
produce the rated capacity of 6 MW across this entire range of wind speeds. Finally, when wind speed exceeds the cut-out wind speed $v_{\text{cut}}$ of 25 m/s, the turbine produces no electric power.

The SWT-6.0-154 power curve was used to estimate wind power production for specific NOAA NDBC and Hywind sites using time series data of wind speed. The model continued to use an assumed air density of 1.184 kg/m$^3$ at 25° C to keep the nominal efficiency $\xi$ constant. Slight variations of air density and efficiency would not have significant impact on the power output, as the power equation is dominated by the cubed wind speed (Equation 2.2). The model extrapolated wind speeds from the buoy height, typically 4 or 5 m, to the turbine hub height of 98.6 m (Statoil 2018a). Hub height wind speed was calculated using a power law as was done by Stoutenburg et al. (2010), who extrapolated wind speeds to 80 m hub height assuming neutral atmospheric stability with the method described by Hsu et al. (1994). The power law profile for wind states that:

$$\frac{u_2}{u_1} = \left(\frac{z_2}{z_1}\right)^P$$

(3.1)

where $u_2$ (m/s) is the wind speed at hub height $z_2$ (m), $u_1$ (m/s) is the observed wind speed at the anemometer height $z_1$ (m), and $P$ is the power coefficient. $P$ is a function of atmospheric stability and the ocean surface characteristics, and is equal to 0.11 experimentally or 0.10 theoretically (Hsu et al. 1994). Using $P = 0.11$ and $z_2 = 98.6$ m, the hub height wind speed time series was estimated for a site using its anemometer height $z_1$ and observed wind speed series $u_1$ by Equation 3.2:

$$u_2 = u_1 \times \left(\frac{98.6}{z_1}\right)^{0.11}$$

(3.2)

Though not perfectly accurate for uniform terrain with turbulence, the power law wind profile can be used in engineering practice to approximate wind speeds at heights with reasonable accuracy (Panofsky and Dutton 1984).

The wind power model calculated time series wind power for a single SWT-6.0-154 turbine using the hub height wind speed time series $u_2$, Equation 2.2, and the SWT-6.0-154 power curve. Analysis was conducted for a 24-MW wind farm, consisting of six SWT-6.0-154 turbines. Power output of a single turbine was multiplied by a factor of six
in the wind-only analysis, labeled Farm 1, to produce the total wind farm capacity of 24 MW.

**Chapter 3.2.2 Wave Power Model**

The wave power model was used to predict available wave power and Pelamis WEC power for NOAA NDBC and Hywind sites. Available wave power was modeled according to linear wave theory as discussed in Chapter 2.2.1, which is particularly applicable for the deeper water sites investigated with depths of 35 m or greater.

Available wave power was calculated using Equation 2.4, reproduced below:

\[ P_{\text{wave}} = \frac{\rho_w g H^2 T}{32\pi} \]  

(2.4)

The model assumed a sea surface temperature of 25° C and sea water density \( \rho_w = 1023 \) kg/m\(^3\) (Engineering Toolbox n.d.f). This predicted the available wave power per meter of wave front \( b \). The actual estimated power production by a specific wave energy converter was calculated for comparison to the wind power production. Wave power was calculated for the Pelamis WEC, continuing upon the analyses conducted by Stoutenburg et al. (2010) and Fusco et al. (2010). The Pelamis WEC was used for this study because of its well-documented, ocean-tested performance in a variety of sea state conditions. The published power matrix from Previsic et al. (2004), which analyzed a potential wave power farm using Pelamis devices near San Francisco, California, was used for Pelamis wave power calculations.

**Table 3.3 Pelamis Wave Energy Conversion Absorption Performance, from Previsic et al. (2004)**

<table>
<thead>
<tr>
<th>Tp (s)</th>
<th>3.2</th>
<th>3.5</th>
<th>4.0</th>
<th>4.5</th>
<th>5.0</th>
<th>5.5</th>
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<th>8.0</th>
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<tr>
<td>H (m)</td>
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</tbody>
</table>

34
The power matrix in Table 3.3 defines the power output for a single 750 kW Pelamis WEC for various combinations of wave height and wave period conditions. The model rounded time series wave height and wave period data to the nearest value shown in Table 3.3. Data were rounded using the Table 3.3 values as center points; for example, wave heights between 8.25 and 8.75 m were rounded to 8.5 m, and wave heights between 8.75 m and 9.25 m were rounded to 9 m. Because no data are shown for a wave period of \( T_p = 19 \) s in Table 3.3, all wave periods between 18.5 s and 20.5 s were rounded to 20 s. The Pelamis power matrix and average power curves depict power production for different wave height and period conditions in Figure 3.4.

*Figure 3.4 Pelamis WEC Power Matrix and Average Power Curves. The power curve as a function of wave height is for power averaged across all wave periods, and the power curve as a function of wave period is for power averaged across all wave heights.*
The Pelamis WEC produces power for higher wave heights of the 0.125-10m range. It produces closest to its rated capacity of 750 kW on the upper end of this wave height range across all wave periods from 3-20s. It produces smaller amounts of power at slightly lower wave heights, but very little power at small wave heights. This is exemplified in the power curve averaged across wave period, which shows a consistent increase in power production as wave height increases, though the rate of production increase diminishes as height increases beyond 5-6 m. Power production is driven by wave height rather than by wave period, as the Pelamis WEC can produce at or close to the nominal capacity of 750 kW for the entire range of wave periods if the wave height is great enough. It also appears to be skewed towards slightly better power production for lower wave periods, particularly when it is not operating at full capacity. Power output peaks for a wave period between 7-8 s for the averaged wave height, though the overall variation of power production is less across the range of wave periods than it is across the range of wave heights. Thus, Pelamis power production is more sensitive to wave height conditions than wave period.

Using the rounded significant wave height, dominant wave period, and wave power model, we calculated time series of available wave power and Pelamis wave power estimated for a single Pelamis WEC. Analysis was conducted for a 24-MW wave farm, consisting of 32 Pelamis WEC devices. Power from a single WEC was multiplied by a factor of 32 in the wave-only analysis, labeled Farm 5, to produce the total wave farm capacity of 24 MW.
Chapter 3.2.3 Combined System Power Model

Combined system power outputs were calculated by adding the SWT-6.0-154 wind power model results and Pelamis wave power model results. Several integrated system layouts with different percent capacity breakdown were investigated, summarized in Table 3.5.

<table>
<thead>
<tr>
<th>Farm Name</th>
<th>Total capacity (MW)</th>
<th>Percent Capacity (Wind% - Wave%)</th>
<th>Capacity (Wind MW – Wave MW)</th>
<th># of Devices (Wind – Wave)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Farm 1</td>
<td>24</td>
<td>100-0</td>
<td>24-0</td>
<td>4-0</td>
</tr>
<tr>
<td>Farm 2</td>
<td>24</td>
<td>75-25</td>
<td>18-6</td>
<td>3-8</td>
</tr>
<tr>
<td>Farm 3</td>
<td>24</td>
<td>50-50</td>
<td>12-12</td>
<td>2-16</td>
</tr>
<tr>
<td>Farm 4</td>
<td>24</td>
<td>25-75</td>
<td>6-18</td>
<td>1-24</td>
</tr>
<tr>
<td>Farm 5</td>
<td>24</td>
<td>0-100</td>
<td>0-24</td>
<td>0-32</td>
</tr>
</tbody>
</table>

Whereas Farm 1 consists of 100% wind power capacity (24 MW, 4 wind turbines) and Farm 5 consists of 100% wave power capacity (24 MW, 32 WECs), Farm 2, Farm 3, and Farm 4 are integrated wave-wind systems with varying levels of wind and wave capacity contributions to the same total farm capacity of 24 MW. Progressing from Farm 1 to Farm 5, wind power capacity decreases incrementally by 25% of farm capacity (6 MW) and wave power capacity increases by the same amount. Farm 2 is comprised of 75% wind power capacity (18 MW, 3 wind turbines) and 25% wave power capacity (6 MW, 8 WECs), Farm 3 consists of an equal amount of 50% wind power capacity (12 MW, 2 wind turbines) and 50% wave power capacity (12 MW, 16 WECs), and Farm 4 is comprised of 25% wind power capacity (6 MW, 1 wind turbine) and 75% wave power capacity (18 MW, 24 WECs). Only the relative contributions of wind and wave power to the total farm capacity were considered in this analysis, as this determined the power variability. Potential layouts of these integrated systems were not investigated in this thesis.

For each farm system, the hourly average, daily average, monthly average, and annual average power output and capacity factor were computed. This enabled analysis of power variability on multiple time scales, including hourly variability, diurnal variability, seasonal variability, and inter-annual variability. Hourly variability is defined
as the variability of hourly average power output for the entire duration of a site’s data, and was used as a proxy for the overall variability of the system. Diurnal variability is the hourly variability over a representative, or average, day, and indicates how power output for wind and wave systems typically behaves at different times of the day. Seasonal variability is the variability of monthly average power output over the course of a year and indicates how power output typically behaves at different times of the year. Finally, inter-annual variability is the variability of annual average power output for the entire duration of a site’s data, and shows how power output might change at a site from year to year.

This analysis was conducted for each station considered in Table 3.1. Comprehensive regional sites, namely East Coast Comprehensive and West Coast Comprehensive, were determined by including power results from all sites within a particular region for all years of data analyzed; overlapping data at the same time for different sites were averaged on an hourly basis to create the Comprehensive sites. Daily, monthly, and annual averages were then computed for each Comprehensive site. Thus, the Comprehensive sites consist of several years of data for a particular region, with overlapping times averaged together across sites. Representative regional sites, namely East Coast Representative and West Coast Representative, were determined by averaging hourly power results from all sites within a particular region across all years of data analyzed. This yielded a single year of representative data for the East Coast Representative site and for the West Coast representative site, and daily, monthly, and annual averages were computed based on this hourly data for one year. Thus, the Representative sites consist of an average year of data for a particular region, determined by averaging all years of data across all sites. This provided two groupings of regional data, Comprehensive and Representative, that enabled different types of analysis. It is important to note that both groupings have different durations of power output results for different sites; thus, stations with longer data sets influenced the Comprehensive and Representative sites more than stations with shorter data sets. For example, Station 41009 with 6 years of consecutive data analyzed influences the East Coast Comprehensive and Representative data sets more than Station 44008 with 2 years of consecutive data. The model assumed that the correlations and variability observed occur on a much shorter
time-scale than the duration of data collected (2-9 years), so wind and wave weather patterns occurred many times for each data set. This enabled averaging across sites to determine regionally representative sites, though statistical parameters like the mean and standard deviation were more influenced by sites with a longer period of data analysis.

Regional power output was compared using the Kolmogorov-Smirnov hypothesis test for nonparametric data. Nonparametric data describes data sets with distributions that are not well-known (normal, Weibull, Poisson, binomial, etc.) (Bonnini et al. 2014). This describes power output for wind, wave, and combined wave-wind farms well, as the distributions for these variables do not follow typical probability distributions. The Kolmogorov-Smirnov test was used for comparison of the relative size of power distributions between regions. The test assumed that the two distributions are random samples from two continuous populations, and that the distributions were mutually independent (Bonnini et al. 2014). Three sets of null and alternative hypotheses can be tested with the Kolmogorov-Smirnov test. The first tests the null hypothesis that the distributions $F_1(x)$ and $F_2(x)$ were the same and alternative hypothesis that the distributions were different.

Null Hypothesis $H_{F_1=F_2}: \{F_1(x) = F_2(x) \forall x \in \mathbb{R}\}$  \hspace{1cm} (3.3A)

Alternative Hypothesis $H_{F_1\neq F_2}: \{F_1(x) \neq F_2(x) \text{ for some } x \in \mathbb{R}\}$  \hspace{1cm} (3.3B)

This test can be used to determine whether two data sets are identical, but in cases when they are not it does not indicate what the relative differences are. Instead, we are interested in the stochastic dominance of one distribution over another, or the tendency for that distribution to be larger. The Kolmogorov-Smirnov test is used to state with statistical confidence the relative shape differences and stochastic dominance of one regional distribution over another, but does not precisely quantify these differences. The second Kolmogorov-Smirnov test tests the null hypothesis that the first distribution was stochastically dominant over, or statistically larger than, the second distribution, which means its empirical distribution function (EDF) was less than the other distribution’s EDF. This was tested against the alternative hypothesis that the first distribution was stochastically smaller than the second distribution, meaning its EDF is greater.
Null Hypothesis $H_{F_1 \geq F_2}: \{ F_1(x) \leq F_2(x) \forall x \in \mathbb{R} \}$ (3.4A)

Alternative Hypothesis $H_{F_1 \leq F_2}: \{ F_1(x) \geq F_2(x) \text{ for some } x \in \mathbb{R} \}$ (3.4B)

The Kolmogorov-Smirnov one-sided test tests the EDF of the distributions, leading to counter-intuitive null and alternative hypothesis. The test in Equation 3.4A and Equation 3.4B actually tests the null hypothesis that $F_1$ is typically larger than $F_2$ and the alternative hypothesis, which we suspect to be true, that $F_1$ is typically smaller than $F_2$. This is the reverse of what is shown by the equivalence expression for these equations, however, because the Kolmogorov-Smirnov tests the EDF of the data set. Thus, if we suspect that $F_1$ is smaller than $F_2$, we actually test the alternative hypothesis that $F_1(x) \geq F_2(x)$ and null hypothesis that $F_1(x) \leq F_2(x)$. If $F_1$ is in fact smaller than $F_2$, then its EDF will be higher for values closer to zero, so the EDF $F_1(x)$ is greater than the EDF $F_2(x)$. Conversely, the third Kolmogorov-Smirnov test tests the null hypothesis that the first distribution was stochastically smaller than the second distribution, meaning its EDF was greater, against the alternative hypothesis that the first distribution was stochastically larger than the second distribution, meaning its EDF was greater.

Null Hypothesis $H_{F_1 \leq F_2}: \{ F_1(x) \geq F_2(x) \forall x \in \mathbb{R} \}$ (3.5A)

Alternative Hypothesis $H_{F_1 \geq F_2}: \{ F_1(x) \leq F_2(x) \text{ for some } x \in \mathbb{R} \}$ (3.5B)

This is a non-intuitive notation for the Kolmogorov-Smirnov one-sided hypothesis tests. In this thesis, the suspected behavior of the two distributions can be interpreted based on the subscript of the alternative hypothesis. For Equations 3.4A and 3.4B we suspect that $F_1$ is smaller than $F_2$, and for Equations 3.5A and 3.5B we suspect that $F_1$ is greater than $F_2$. Different alternative hypotheses were selected for wind and wave power distributions based on the distribution shapes and expected results. The Kolmogorov-Smirnov tests were tested at a confidence level of $\alpha = 0.05$; tests that resulted in a $p$-value less than this confidence interval indicated that we should reject the null hypothesis and accept the alternative hypothesis with 95% confidence. Additionally, lower $p$-values suggested even higher confidence in the validity of the alternative hypothesis.
Chapter 3.3 Environmental Loading

The floating spar-buoy and wind turbine are subjected to environmental forces, driven primarily by wind loading and wave loading. Separate models were produced to characterize the impact of wind loading and wave loading on a generalized spar-buoy structure.

Chapter 3.3.1 Wind Loading Model

A wind load model was produced for a generalized spar-buoy. The precise design of the spar-buoy was not available, so analysis was conducted for a generalized case in terms of the important physical parameters.

Figure 3.6 shows a generalized spar-buoy floating upright in the water with no wind loading. The model assumed that the spar-buoy floats upright with no pitching when there is no wind loading present. The foundation is ballasted to an idealized center of gravity at the base of the buoy, shown in red. The green center of buoyancy is kept above the red center of gravity and the black fixed point. The black fixed point is held in place by mooring lines and is located where the mooring lines connect to the foundation; thus, it is the center of rotation when the structure tilts. It is possible that the fixed point would actually be located above the center of buoyancy or below the center of gravity, depending on the design of the specific spar-buoy concept. Analysis was conducted for a
central fixed point between the center of buoyancy and center of gravity because this enables the buoyant force $F_B$ and gravitational force $F_G$ to work in tandem to resist the wind force $F_W$, which minimizes the tilt angle. The length $L$ is defined as the total length of the spar-buoy, wind length $L_W$ is the length from the fixed point to the turbine hub height, buoyant length $L_B$ is the length from the fixed point to the center of buoyancy, and gravitational length $L_G$ is the length from the fixed point to the center of gravity. Results would be the same if the center of gravity is not idealized to the very bottom of the turbine but instead shifted up such that $L_W$ shortens, as long as it remains below the fixed point.

When a constant wind force $F_W$ acts on the turbine, it causes the spar-buoy to pitch back by an angle $\theta$. The force due to wind acting on a wind turbine is modeled with:

$$F_W = \frac{1}{2} C_D \rho_{air} A u^2$$  \hspace{1cm} (3.6)

where $F_W$ is the wind force (N), $C_D$ is the drag coefficient, $\rho_{air}$ is the air density (1.184 kg/m$^3$), $A$ is the area (18,600 m$^2$), and $u$ is the wind speed (m/s) (Engineering Toolbox n.d.j; n.d.c). In reality, the wind force changes with the wind velocity and therefore neither $F_W$ nor $\theta$ is constant. The model assumed a constant wind speed and force to enable an analytical solution of the rotational equation of motion of the spar-buoy. It also assumed that the wind force acts entirely at the turbine hub height as a point load, rather
than along the entire length of the turbine tower. The buoyant force of the buoy can be calculated with:

\[
F_B = \rho_{water} g V_{submerged}
\]  

(3.7)

where \(\rho_{water}\) is the density of seawater (1023 kg/m\(^3\)), \(g\) is gravitational acceleration (9.81 m/s\(^2\)), and \(V_{submerged}\) is the submerged volume of the spar-buoy (m\(^3\)) (Engineering Toolbox n.d.e; n.d.f). The model assumed that the submerged volume does not appreciably change based on the value of the pitch angle \(\theta\) between Figure 3.6 and Figure 3.7. Finally, the gravitational force is calculated with:

\[
F_G = mg
\]  

(3.8)

The wind force \(F_W\) creates a torque on the buoy that acts at a perpendicular vertical distance \(L_W \cos(\theta)\). When the center of rotation is between the centers of mass and buoyancy, this is counteracted by the vertical buoyant force \(F_B\) which creates a torque on the buoy that acts at a perpendicular horizontal distance \(L_B \sin(\theta)\), and by a vertical gravitational force \(F_G\) which creates a torque on the buoy that acts at a perpendicular horizontal distance \(L_G \sin(\theta)\).

The net force was first considered for the two-dimensional steady state case. The sum of the forces in the horizontal \(x\) and vertical \(y\) directions are zero at steady state:

\[
\sum F_x = F_W + T_x = 0 \quad (3.9A)
\]

\[
\sum F_y = F_B + F_G + T_y = 0 \quad (3.9B)
\]

where \(T_x\) is the component of cable tension acting in the horizontal direction (N) and \(T_y\) is the component of cable tension acting in the vertical direction (N). The model assumed that there is no translational motion of the spar-buoy, so Equations 3.9A and 3.9B are true for all cases considered. The wind, buoyant, and gravitational forces all contribute a torque around the fixed point of the buoy, whereas the cable tension acts at the fixed point and therefore produces no moment. The sum of the torques are equal to zero at steady state when no rotation occurs:

\[
\sum \tau = F_W L_W \cos(\theta) - F_B L_B \sin(\theta) - F_G L_G \sin(\theta) = 0 \quad (3.10)
\]

where \(\tau\) is torque (Nm). At steady state, the pitch angle \(\theta_{ss}\) can be found by:

\[
\theta_{ss} = \tan^{-1}\left(\frac{F_W L_W}{F_B L_B + F_G L_G}\right) \quad (3.11)
\]
However, the spar-buoy is not always at steady-state even when the wind force is constant. It is helpful to understand the behavior of the system for transient conditions, which indicate how the turbine would pitch as it adjusts to a new wind speed and new steady-state. The spar-buoy pitching can be modeled as a rotating pendulum using the rotational spring-damper equation:

\[
I \frac{d^2 \theta}{dt^2} + D \frac{d\theta}{dt} + k\theta = \sum \tau
\]  

(3.12A)

where \( I = \int r^2 \, dm \) is the moment of inertia of the system (\( r \) is the distance from the center of rotation to a given point with mass \( dm \)), \( D \) is the damping coefficient due to drag in the water (\( \frac{kgm^2}{s} \)), and \( k \) is a rotational spring constant. There is no internal spring in the spar-buoy, so \( k = 0 \) and the gravitational and buoyant torques instead provide the restoring moment, as in a pendulum problem:

\[
I \frac{d^2 \theta}{dt^2} + D \frac{d\theta}{dt} + (F_B L_B + F_G L_G)\theta = F_W L_W \cos(\theta)
\]  

(3.12B)

\[
I \frac{d^2 \theta}{dt^2} + D \frac{d\theta}{dt} + (F_B L_B + F_G L_G)\sin(\theta) = F_W L_W \cos(\theta)
\]  

(3.12C)

A numerical solution can be obtained for the general problem for larger \( \theta \). To obtain an analytical solution, the model assumes small angular deflections, enabling the use of the small-angle approximation of \( \sin(\theta) = \theta \) and \( \cos(\theta) = 1 \). This yields the approximation:

\[
I \frac{d^2 \theta}{dt^2} + D \frac{d\theta}{dt} + (F_B L_B + F_G L_G)\theta = F_W L_W
\]  

(3.12D)

It is evident that the buoyant and gravitational forces work in tandem to restore the pitch angle to its steady state when the turbine is under a constant wind load in Equation 3.12D. This rotational spring equation can be solved for the three cases of critical damping, overdamping, and underdamping. The torque expressions are simplified to \( \tau_{buoy} = F_B L_B + F_G L_G \) and \( \tau_{wind} = F_W L_W \) for expedience. For all three regimes, the homogeneous equation yields the expression for the eigenvalues of \( \theta \):

\[
\lambda_{1,2} = \frac{-D \pm \sqrt{D^2 - 4I\tau_{buoy}}}{2I}
\]  

(3.13)
where $\lambda_{1,2}$ are the eigenvalues of Equation 3.12D. The three cases of critical damping, overdamping, and underdamping depend on whether there is one real eigenvalue, two distinct real eigenvalues, or a complex conjugate pair of eigenvalues.

Case 1. Critical Damping: $D^2 - 4I\tau_{buoy} = 0$  

Case 2. Overdamping: $D^2 - 4I\tau_{buoy} < 0$  

Case 3. Underdamping: $D^2 - 4I\tau_{buoy} > 0$

The critical value for the damping coefficient can be found from these expressions. $D_{critical}$ is the damping coefficient for critical damping of the system, and the system is overdamped if $D > D_{critical}$ and underdamped if $D < D_{critical}$.

$$D_{critical} = 2\sqrt{I\tau_{buoy}}$$  

Three equations for $\theta$ are derived for a critically damped system, overdamped system, and underdamped system depending on the value of the damping coefficient $D$. The derivation of these general solutions is presented in Appendix A. These solutions are:

Case 1. Critical Damping

$$\theta(t) = c_1 e^{-\frac{\tau_{buoy}}{t}} + c_2 t e^{-\frac{\tau_{buoy}}{t}} + \frac{\tau_{wind}}{\tau_{buoy}}\tau_{buoy}$$  

where $c_1 = \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}}$

and $c_2 = \omega_0 + \frac{\sigma_{buoy}}{2} \left( \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}} \right)$

Case 2. Overdamping

$$\theta(t) = c_1 e^{-\frac{D + \sqrt{D^2 - 4I\tau_{buoy}}}{2I}t} + c_2 t e^{-\frac{D - \sqrt{D^2 - 4I\tau_{buoy}}}{2I}t} + \frac{\tau_{wind}}{\tau_{buoy}}\tau_{buoy}$$  

where $c_1 = \frac{\theta_0}{2} - \frac{\tau_{wind}}{2\tau_{buoy}} + \frac{\omega_0 I}{\sqrt{D^2 - 4I\tau_{buoy}}} + \frac{D\theta_0}{2\sqrt{D^2 - 4I\tau_{buoy}}} - \frac{D\tau_{wind}}{2\tau_{buoy}\sqrt{D^2 - 4I\tau_{buoy}}}$

and $c_2 = \frac{\theta_0}{2} - \frac{\tau_{wind}}{2\tau_{buoy}} - \frac{\omega_0 I}{\sqrt{D^2 - 4I\tau_{buoy}}} - \frac{D\theta_0}{2\sqrt{D^2 - 4I\tau_{buoy}}} + \frac{D\tau_{wind}}{2\tau_{buoy}\sqrt{D^2 - 4I\tau_{buoy}}}$
Case 3. Underdamping

\[ \theta(t) = c_1 e^{-\frac{D}{2}\tau} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + c_2 e^{-\frac{D}{2}\tau} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + \frac{\tau_{wind}}{\tau_{buoy}} \] (3.16C)

where \( c_1 = \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}} \)

and \( c_2 = \frac{2\omega I + D(\theta_0 - \frac{\tau_{wind}}{\tau_{buoy}})}{\sqrt{-D^2 + 4I\tau_{buoy}}} \)

Chapter 3.3.2 Wave Loading Model

The impact of waves must be considered in the design of offshore structures. Many different models exist for determining the force imparted on a structure by a wave, depending on whether a linear approximation is applicable (Matha et al. 2011). The Morrison equation is commonly used to calculate the wave force for a linear wave:

\[ F_{\text{wave}} = \frac{1}{2} \rho_{\text{water}} C_d u |u| A_{\text{projected}} + \rho_{\text{water}} C_m V_{\text{submerged}} \frac{du}{dt} \] (3.17)

where \( F_{\text{wave}} \) is the wave force (N), \( \rho_{\text{water}} \) is the density of seawater (1023 kg/m\(^3\) at 25\(\degree\) C), \( C_d \) is the dimensionless drag coefficient, \( u \) is the wave particle velocity relative to the velocity of the structure (m/s), \( A_{\text{projected}} \) is the area on which the wave force acts (m\(^2\)), \( C_m \) is the dimensionless inertial coefficient, \( V_{\text{submerged}} \) is the submerged volume of the structure (m\(^3\)), and \( \frac{du}{dt} \) is the wave particle acceleration (m/s\(^2\)) (Sarpkaya 2010; McCormick 2010; Wittbrodt et al. 2013). The horizontal wave particle velocity \( u \) is different from the wave velocity or celerity \( c \), respectively defined by McCormick (2010) and Rubin and Atkinson (2001) as:

\[ u = \frac{H \omega \cosh(k(z + h))}{2 \sinh(kh)} \cos(kx - \omega t) \] (3.18)

\[ c = \frac{\omega}{k} \] (3.19)

where \( \omega \) is the wave frequency (\( \omega = \frac{2\pi}{T} \) rad/s), \( H \) is the significant wave height (m), \( k \) is the wave number (\( k = \frac{2\pi}{\lambda} \)), \( z \) is the vertical coordinate (m), and \( h \) is the water depth (m) (McCormick 2010; Rubin an Atkinson 2001). Taking the derivative of the horizontal
wave particle velocity with respect to time yields the horizontal wave particle acceleration:

\[
\frac{du}{dt} = -\frac{H\omega^2 \cosh(k(z + h))}{2 \sinh(kh)} \sin(kx - \omega t)
\]  

(3.20)

Solving Equation 3.18 and Equation 3.20 for the horizontal wave particle velocity and acceleration enables the calculation of the horizontal wave force using the Morrison equation (Equation 3.17). However, three conditions must be satisfied before the Morrison equation can be applied:

\[ KC = \frac{u_0 T}{D} > 6 \]  

(3.21A)

\[ d_{fr} = \frac{\pi D}{\lambda} \ll 0.5 \]  

(3.21B)

\[ \lambda > 5D \]  

(3.21C)

where \( KC \) is the dimensionless Keulegan-Carpenter number, \( d_{fr} \) is the diffraction parameter, \( u_0 \) is the amplitude of the fluid velocity (m/s), \( T \) is the wave period (s), \( D \) is the cylinder diameter (m), and \( \lambda \) is the wavelength (m) (Wittbrodt et al. 2013). For linear waves, the amplitude of the fluid velocity is defined by McCormick (2010) as:

\[ u_0 = \omega \frac{H \cosh(k(z + h))}{2 \sinh(kh)} \]  

(3.22)

It is also necessary to determine the drag coefficient \( C_d \) and inertial coefficient \( C_m \) for use in Equation 3.17. These coefficients are functions of the Reynold’s number \( Re \), the Keulegan-Carpenter number \( KC \), and the reduced body surface roughness \( \dot{\varepsilon} \). The Reynold’s number and reduced body surface roughness are defined as:

\[ Re = \frac{u_0 D}{\nu} \]  

(3.24)

\[ \dot{\varepsilon} = \frac{K}{D} \]  

(3.25)

where \( \nu \) is the kinematic viscosity of water (9.38e-7 m²/s) (Engineering Toolbox n.d.f) and \( K \) is the surface roughness (Wittbrodt et al. 2013). The values for the drag coefficients \( C_d \) and \( C_m \) are well-documented and can be determined from charts based on the \( KC \) number (McCormick 2010).

Equation 3.17 is used to determine the force imparted by linear waves on the spar-buoy cylindrical shaft. There are limitations to the Morrison equation, however; it
neglects the effects of wave diffraction due to interaction with the structure, and assumes that viscous drag dominates the drag forces so that wave radiation damping is ignored, both of which may not be accurate for floating substructures (Matha et al. 2011). While there are a number of assumptions and limitations to this analysis, including neglecting wave diffraction, wave radiation damping, slap and slam loading in shallow-water and breaking waves, second-order wave forces, and vortex-induced vibrations (Matha et al. 2010), the Morrison equation can be used as a basis for analysis of wave loading on offshore wind turbines.

Computational fluid dynamics (CFD) analysis of similarly sized waves was conducted using SimScale. A wind turbine and spar-buoy foundation model was produced in Rhinoceros by Maider Llaguno-Munitxa. The wind turbine model approximated the dimensions of the Hywind Scotland spar-buoy using publicly available information. The CAD model was uploaded into the online CFD solver SimScale. A large boundary box mesh was produced that encompassed the turbine and an upstream and downstream region. A calm sea state was defined downstream of the wind turbine and 5 m upstream such that the turbine foundation was submerged up to 78 m. A single wave was defined at a given wave height $H$ above 78 m. Both sea states were prescribed material conditions of density $\rho_{\text{water}} = 1023 \text{ kg/m}^3$ and kinematic viscosity $\nu_{\text{water}} = 9.38 \times 10^{-7} \text{ m}^2/\text{s}$ (Engineering ToolBox n.d.f). The surrounding air above the water surface and around the turbine was set with $\rho_{\text{air}} = 1.184 \text{ kg/m}^3$ and $\nu_{\text{air}} = 1.55 \times 10^{-5} \text{ m}^2/\text{s}$ (Engineering ToolBox n.d.c; n.d.d). Initial conditions were set to zero, so that the modified pressure value was 0 Pa and velocity in the $x$, $y$, and $z$ directions were all 0 m/s. Boundary conditions consisted of assigning the mesh bounding box and turbine components as walls to fix them in place in the model. The CFD solver used a laminar turbulence model and transient flow conditions, and simulated 8 seconds of flow at a time step of 0.001 seconds. This model setup with two sea states at different initial heights induced wave flow due to gravity and hydrostatic pressure of the higher wave height elevation. By defining the wave region at a higher elevation than the surrounding flat sea, with a surface tension of 0.07 kg/s$^2$ (Engineering ToolBox n.d.g) and gravity of 9.81 m/s$^2$ in the $-z$ direction for both regions, there was a higher fluid pressure at the same elevation under the wave than under the flat sea. The combined effects of this higher fluid
pressure and falling water due to gravity caused the wave to propagate downstream towards the wind turbine, where it imparted a pressure on the turbine foundation. The wave was initialized 8 m away from the turbine to allow the wave to develop more typical wave behavior before reaching the structure.

The Morrison equation and CFD computation were used to analyze the wave force on the foundation for different wave heights. The base case consisted of a linear wave with $H = 10$ m and $T = 5$ s. The available wave power was calculated for the base case with Equation 2.4, yielding 489.65 kW/m. Successive wave heights were determined by assuming a percent power extraction by a wave energy converter and back-calculating the wave height assuming the wave period remained the same, shown in Table 3.8.

<table>
<thead>
<tr>
<th>Base Case Wave Height (m)</th>
<th>Base Case Power (kW/m)</th>
<th>Percent Power Extraction (%)</th>
<th>Extracted Wave Power (kW/m)</th>
<th>Remaining Wave Power (kW/m)</th>
<th>Remaining Wave Height (m)</th>
<th>Percent Wave Height Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>0</td>
<td>0.00</td>
<td>489.65</td>
<td>10.0</td>
<td>0.00</td>
</tr>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>10</td>
<td>48.96</td>
<td>440.68</td>
<td>9.49</td>
<td>5.13</td>
</tr>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>20</td>
<td>97.93</td>
<td>391.72</td>
<td>8.94</td>
<td>10.56</td>
</tr>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>30</td>
<td>146.89</td>
<td>342.75</td>
<td>8.37</td>
<td>16.33</td>
</tr>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>40</td>
<td>195.86</td>
<td>293.79</td>
<td>7.75</td>
<td>22.54</td>
</tr>
<tr>
<td>10.0</td>
<td>489.65</td>
<td>50</td>
<td>244.82</td>
<td>244.82</td>
<td>7.07</td>
<td>29.29</td>
</tr>
</tbody>
</table>

The relationships between the available wave power and the percent power extracted and the significant wave height and percent power extracted are shown in Figure 3.9. Note
that these figures show power extraction up to 100%, while wave loads were only calculated for power extraction up to 50%. This was done to reflect a more reasonable range of power conversion efficiency for WECs up to 50%. The wave force or pressure on the submerged portion of a spar-buoy was calculated for each of the wave heights listed in Table 3.8 using Morrison’s equation and the CFD model in SimScale.
Chapter IV. Results

Chapter 4.1. Power Variability

Power variability of offshore wind farms, wave farms, and combined wave-wind systems is investigated at multiple time-scales. These include the overall hourly variability, inter-annual variability, seasonal variability, and diurnal variability.

Chapter 4.1.1. Distributions and Hourly Variability

Probability density functions are produced for each farm system using hourly averaged data for each site and the Comprehensive regional sites. Typical power output and variability can be compared between different wave-wind farm layouts using the distributions’ summary statistics, including mean, median, standard deviation, and first and third quartiles.

Figure 4.1. Boxplots of summary statistics of power across farm types and sites. Mean power is represented by the red dot, standard deviation is represented by the blue dot, median is shown as the thicker black line, and the first and third quartiles are the lower and upper edges of the boxes, respectively.
All sites follow a similar trend of decreasing value of mean, median, standard deviation, and first and third quartiles between Farm 1 and Farm 5, indicating typically lower wave power production than wind power production. The East and West Coast sites exhibit very similar behavior for all farm layouts, but the West Coast Farm 5 values are all higher than on the East Coast, indicating more wave energy extraction by the Pelamis WEC on the West Coast. The East Coast and Hywind site follow a similar pattern of decreasing mean and median from Farm 1 to Farm 5, and an increased standard deviation from Farm 4 to Farm 5. The Farm 5 standard deviation is also greater than the mean on the East Coast, while it is only slightly lower than the mean at the Hywind site. The West Coast also follows this trend, but the pattern is not as pronounced and standard deviation does not decrease from Farm 4 to Farm 5. Thus, it appears that wave energy is most variable on the East Coast, followed by the Hywind site and then the West Coast. Wind energy production appears fairly consistent between the East Coast and West Coast but higher at the Hywind site, while wave energy seems to be highest on the West Coast and Hywind site but lower on the East Coast.

The differences in power production across regions for different farm layouts is investigated more thoroughly using the power distributions for each layout and the Kolmogorov-Smirnov hypothesis test of the relative size of regional distributions. This analysis is not limited to just power, but is also conducted for environmental factors like wind speed, wave height, and wave period, which give an indication of available energy resources. Wind speed typically follows the Weibull distribution, though this is not always the case. At many sites wind speed follows the special case of the Weibull distribution known as the Rayleigh distribution, which is a Weibull distribution with shape parameter $k$ equal to 2. Other sites may follow distributions that are more affected by seasonal variation, which may be characterized by the double-peaked bi-Weibull distribution (Burton et al. 2011). The Kolmogorov-Smirnov test is used to compare wind speed distributions because it is applicable to known distributions in addition to nonparametric data. The hub height wind speed distributions for the East Coast Comprehensive, West Coast Comprehensive, and Hywind sites are shown in Figure 4.2.
The wind speed distribution is superimposed with the SWT-6.0-154 power curve. Note that the height of the power axis is independent of the height of the probability axis. East Coast wind speed and West Coast wind speed closely resemble each other, while the Hywind site exhibits two peaks instead of one. Comparing the East Coast wind speed to the West Coast wind speed, we test the Kolmogorov-Smirnov null hypothesis that East Coast wind speeds are typically smaller than West Coast wind speeds against the alternative hypothesis that they are typically larger on the East Coast, yielding a very small \( p\)-value \(< 2.22\times10^{-16} \). Assuming a significant level of \( \alpha = 0.05 \) for all tests, we reject the null hypothesis and conclude that East Coast wind speeds are typically larger than West Coast wind speeds for the observed distributions. Comparing the East Coast wind speed to the Hywind wind speed, we state the reverse null and alternative hypothesis, testing the null hypothesis that East Coast wind speeds are typically larger than Hywind...
wind speeds and the alternative hypothesis that they are smaller. This yields a very small $p$-value $= 5.37e-57$, so we reject the null hypothesis and conclude that Hywind wind speeds are typically larger than East Coast wind speeds. This is conducted again with the same null and alternative hypotheses for West Coast wind speed and Hywind wind speed, yielding $p$-value $= 6.42e-68$, indicating that we should reject the null hypothesis and conclude that Hywind wind speeds are also larger than West Coast wind speeds. Thus, the Hywind site exhibits the highest wind speeds, followed by the US East Coast and then the US West Coast.

Unlike wind speed, wind power does not typically follow the Weibull distribution due to the constraints of the wind turbine and its power curve. This makes the Farm 1 wind power distribution a nonparametric distribution, as shown in Figure 4.3.

![Wind power distributions across sites](image)

*Figure 4.3 Wind power (Farm 1) distributions across sites*
Figure 4.3 shows the 100% wind power Farm 1 probability distributions across sites. East and West Coast regions follow very similar patterns, with left-skewed distributions and a high probability of producing very little to no power (0-1 MW). For both sites, there is a sharp increase in probability of producing close to the maximum rated power (23-24 MW). The East Coast no-power probability is less than on the West Coast, and the East Coast maximum power spike is greater than on the West Coast. This general trend is also true of the Hywind site, which exhibits an even higher spike in probability of producing close to maximum power. The left-skewed shape is also apparent at the Hywind site, without the sudden increase towards producing very little power. Based on the Kolmogorov-Smirnov results for wind speed, we test the null hypothesis that East Coast wind power is less than West Coast wind power with alternative hypothesis that East Coast wind power is greater than West Coast wind power. This yields a very small \( p\)-value < 2.22e-16. Thus, we reject the null hypothesis and conclude that East Coast wind power is greater than West Coast wind power. Similarly, the null hypothesis that East Coast wind power is greater than Hywind wind power is rejected based on a \( p\)-value = 8.30e-58, indicating that Hywind power is typically larger than on the East Coast. Likewise, we reject the same null hypothesis for the comparison of West Coast wind power and Hywind wind power based on \( p\)-value = 2.61e-68, and conclude that Hywind wind power is stochastically dominant over East Coast wind power, which is stochastically dominant over West Coast wind power. This follows the same trend as the relative rankings of wind speeds across regions, confirming those results. It is important to note that the higher wind speed and wind power of the Hywind site may be due to the shorter time span of available data of just two months, collected entirely during the winter when capacity factor tends to be higher in Scotland. The Hywind wind speed and wind power distributions are likely skewed rightward because of this, and may exhibit behavior more similar to the East Coast and West Coast distributions if data were analyzed for an entire year.

Wave distributions do not appear ideal for power production by the Pelamis WEC for any site considered due to the relatively low observed wave heights.
For all three sites, wave height is left-skewed towards low significant wave heights typically less than 5 m (Figure 4.4). Comparing this to Figure 3.4 and Table 3.3, which show ideal Pelamis WEC operation at higher wave heights closer to 10 m, indicates that the Pelamis WEC will produce relatively little power at these sites. Although wave height is still fairly low, West Coast and Hywind sites both exhibit slightly higher wave height
distributions than the East Coast, potentially indicating better wave energy production at these sites. This is confirmed by the Kolmogorov-Smirnov test of East Coast wave height compared to West Coast wave height and Hywind wave height. Testing the null hypotheses that East Coast wave height is greater than West Coast or Hywind wave height yields very small \( p\)-values of \( p\)-value \( < 2.22 \times 10^{-16} \) and \( p\)-value \( = 4.18 \times 10^{-142} \), respectively, indicating sufficient evidence that both West Coast and Hywind wave height are greater than East Coast wave height. Based on the more right-skewed appearance of the West Coast wave height distribution, we test the null hypothesis that West Coast wave height is less than Hywind wave height and alternative hypothesis that it is greater. This yields a \( p\)-value \( = 0.82 \), indicating that we should actually accept the null hypothesis that West Coast wave height is statistically less than the Hywind wave height. Thus, the Hywind site exhibits the highest wave heights, followed by the West Coast and then the East Coast. This relative ranking makes sense when considering the fact that the majority of waves are wind-waves produced by local wind conditions or swells produced by distant wind conditions, so the relative sizes of wave distributions across regions should resemble the relative sizes of wind distributions. However, East Coast wind speed is greater than West Coast wind speed but West Coast wave height is greater than East Coast wave height, and further analysis is required to characterize these sites. It is likely that the typically larger observed waves on the West Coast are from swells rather than wind-waves, as otherwise the typically smaller West Coast wind speeds would result in smaller wave heights as well.

The dominant wave period distribution is relatively similar for all three sites, with the greatest similarity between the East Coast and West Coast sites; the Hywind site appears slightly more left-skewed. However, testing the null hypothesis that the East Coast wave period is less than the Hywind wave period results in \( p\)-value \( = 0.49 \), and we accept the null hypothesis that the East Coast wave period is typically lower than the Hywind wave period despite the leftward skew of the Hywind distribution. By contrast, testing the null hypothesis that the West Coast wave period is less than the Hywind wave period compels us to reject the null hypothesis with \( p\)-value \( = 3.64 \times 10^{-275} \), and conclude that the West Coast wave period is typically higher than the Hywind wave period. Comparing these results to Figure 3.4 shows that the Hywind site, which has the highest
wave height and reasonably low wave period, could be a viable site for the Pelamis WEC. This could be due to design decisions of the Pelamis WEC that tailor it to application in the North Sea, as the WEC was developed in Edinburgh, Scotland (EMEC 2018). The Pelamis WEC power distributions for 100% wave power (Farm 5) are shown below in Figure 4.5.

![Image of power distributions](image)

**Figure 4.5 Wave power (Farm 5) distributions across sites**

Wave power is more likely to produce in the lowest power bin of 0-1 MW on the East Coast, which has a left-skewed distribution. West Coast power is more uniform than either of the other sites, but is still left-skewed towards lower power production. It does, however, appear to operate in the mid-range of power outputs from 4-8 MW more than the East Coast and Hywind site. The Hywind site somewhat resembles this left-skewed distribution, though does not exhibit as high of a probability of very little to no power output. Its distribution is less consistent than the other two sites, likely due to more
sporadic results over the shorter data set. Some of these observations are confirmed with the Kolmogorov-Smirnov test. Testing the null hypothesis that East Coast wave power is greater than West Coast wave power yields a very small \( p-value < 2.22e-16 \). This indicates that East Coast wave power is less than West Coast wave power, which is also in line with the significant wave height differences. Similarly, East Coast wave power is less than Hywind wave power (null hypothesis rejected with \( p-value = 1.33e-114 \)). The comparison between the Hywind site and the West Coast, however, reveals unclear results. Testing the null hypothesis that West Coast wave power is greater than Hywind wave power yields a \( p-value \) of 3.16e-8, which indicates that West Coast wave power is less than Hywind wave power, as predicted by the significant wave height and dominant wave period comparisons. However, testing the opposite null hypothesis that West Coast wave power is less than Hywind wave power yields an even smaller \( p-value \) of 1.76e-16, indicating that the West Coast wave power may actually be greater than Hywind wave power. Either of these statements could be true based on these results, although it is more likely that the West Coast wave power is greater than Hywind wave power due to the much smaller \( p-value \). These inconsistent results must be analyzed further with other methods.

Integrating wind and wave power resources in Farm 2, Farm 3, and Farm 4 leads to unique combinations of the power distributions seen in Figure 4.3 and Figure 4.5. This is exemplified by Farm 2 with 75% wind power capacity and 25% wave power capacity, shown in Figure 4.6.
A combined system changes the power probability density function significantly. The shape of the Farm 2 distribution is similar between the East and West Coasts, with a dominant left-skew and a slight increase in the upper power range between 18-20 MW. The West Coast distribution is shifted slightly towards higher power output than the East Coast distribution, so that Farm 2 is less likely to produce very little power (0-1 MW) on the West Coast than on the East Coast. This same general shape can also be seen at the Hywind site, but the left-skew is not as pronounced. Instead, there is a more prominent spike in power output between 18-23 MW. This lowers the probabilities of producing power in the lower- and mid-ranges. There is a noticeable spike in power output for all sites in the upper range, at around 18 MW on the East Coast and Hywind site and at 19 MW on the West Coast. This is due to the high spike in probability close to maximum power output for Farm 1 (100% wind) in Figure 4.3. The spike shifts towards a lower power value for Farm 2, however, because of the diversification of the power resource.
even when the wind turbines produce at their full rated capacity of 18 MW, the wave energy converters are not as likely to produce at their full rated capacity of 6 MW, decreasing the amount of time the system operates at 24 MW and shifting the observed power probability spike to the left. Testing the null hypothesis that East Coast Farm 2 power is greater than West Coast Farm 2 power results in a very small $p$-value < $2.22e$-$16$. This indicates that the West Coast Farm 2 typically produces more power than the East Coast Farm 2; however, testing the opposite null hypothesis that East Coast Farm 2 power is less than West Coast Farm 2 power results in a $p$-value = 0.03. While this is larger than for the first test, it is still below the significance of $\alpha = 0.05$ and indicates that this opposite null hypothesis should be rejected. The conflicting results require more analysis, and we cannot conclude which region is more suitable for the Farm 2 layout based on this analysis alone. However, the $p$-value for the first test is orders of magnitude less than it is for the second test; while both hypotheses are statistically plausible with 95% confidence, it is more likely that the West Coast Farm 2 produces more power than the East Coast Farm 2. Comparing the East Coast Farm 2 power to the Hywind site, we test the null hypothesis that East Coast Farm 2 power is greater than Hywind Farm 2 power. This yields a $p$-value of $4.40e$-$61$, and we reject the null hypothesis and conclude that Hywind Farm 2 is stochastically dominant over East Coast Farm 2. This is also true of the West Coast site, with a $p$-value of $1.33e$-$46$. Thus, we conclude that the Hywind Farm 2 produces more power than the East Coast and West Coast Farm 2, but cannot definitively conclude which US coast typically produces more power with the Farm 2 layout.
Farm 3 distributions (Figure 4.7), with 50% wind power capacity and 50% wave power capacity, are very similar to Farm 2 distributions (Figure 4.6), but with a less pronounced spike in probability at higher power output. East Coast and West Coast sites follow a similar left-skewed trend, with a rightward shift towards slightly higher power outputs on the West Coast. The spike at higher power outputs observed for the Farm 2 layout shifts leftward towards a lower power value and decreases in size as more wind capacity is replaced by wave capacity in Farm 3. This leftward shift is caused by the lower wind power capacity, so when the wind turbines produce at full capacity they only produce 12 MW. Additionally, the different operating conditions of wind turbines and wave energy converters means less time is spent at this power production for the 50%-50% split capacity Farm 3 than for Farm 1 and Farm 2 that are more dominated by wind power. The Kolmogorov-Smirnov test again yields inconclusive results for the comparison between the East Coast and West Coast. The null hypothesis that East Coast
Farm 3 power is greater than West Coast Farm 3 power is rejected with \( p\)-value < 2.22e-16, but so is the null hypothesis that East Coast Farm 3 power is less than West Coast Farm 3 power with \( p\)-value = 0.03. Thus, it is inconclusive whether the Farm 3 typically produces more power on the East Coast or West Coast, although the lower \( p\)-value suggests that it is more likely that East Coast Farm 3 power is less than West Coast Farm 3 power. Like with Farm 2, Farm 3 produces more power for the Hywind site than on the East Coast site \( (p\)-value = 4.76e-73) and the West Coast site \( (p\)-value = 2.26e-34). The Hywind Farm 3 typically produces more power than both the East and West Coast sites, but it is inconclusive whether the US East Coast or West Coast typically produces more power with the 50%-50% capacity split layout.

![Figure 4.8 Farm 4 (25% wind, 75% wave) power distributions across sites](image)

Farm 4 (Figure 4.8), with 25% wind capacity and 75% wave capacity, follows a similar distribution shape as Farm 2 (Figure 4.6) and Farm 3 (Figure 4.7). The distribution for all sites is left-skewed, shifted slightly towards the right for the West
Coast and Hywind site. Farm 4 does not exhibit the spike at higher power output seen in Farm 1, Farm 2, or Farm 3, however, due to the decreased wind power contribution to the total capacity. The Kolmogorov-Smirnov test again yields inconclusive results for the comparison between the East Coast and West Coast. The null hypothesis that East Coast Farm 4 power is greater than West Coast Farm 4 power is rejected with $p\text{-value} < 2.22\text{e-16}$, as is the null hypothesis that East Coast Farm 4 power is less than West Coast Farm 4 power with $p\text{-value} = 0.03$. We cannot conclude whether Farm 4 typically produces more power on the East Coast or West Coast, as is the case with Farm 3 and Farm 2, although it is more likely that East Coast Farm 4 power is less than West Coast Farm 4 power based on the much smaller $p\text{-value}$. Farm 4 produces more power for the Hywind site than on the East Coast site ($p\text{-value} = 5.40\text{e-108}$) and the West Coast site ($p\text{-value} = 1.41\text{e-10})$. Thus, the Hywind Farm 4 typically produces more power than both the East and West Coast sites, but it is inconclusive whether the US East Coast or West Coast typically produces more power with the 25%-75% capacity split layout. These hypothesis test results for each farm type across regions are summarized in Table 4.9. Conflicting results are reported with the more likely region first (lower $p\text{-value}$).

<table>
<thead>
<tr>
<th>Table 4.9 Comparison of Wave-Wind Farm Power Distributions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Distribution</strong></td>
</tr>
<tr>
<td>Wind speed</td>
</tr>
<tr>
<td>Wave height</td>
</tr>
<tr>
<td>Wave period</td>
</tr>
<tr>
<td>Farm 1</td>
</tr>
<tr>
<td>Farm 2</td>
</tr>
<tr>
<td>Farm 3</td>
</tr>
<tr>
<td>Farm 4</td>
</tr>
<tr>
<td>Farm 5</td>
</tr>
</tbody>
</table>

Other comparisons and methods are considered for further investigation and validation of the initial distribution and hypothesis test results. The percentage of time that each farm layout produces above or below a percentile of the farm capacity, depicted in Figure 4.10, enables comparison of farm types for each site based on the amount of time they produce a certain amount of energy.
Figure 4.10 Percent of time above or below power capacity percentile. Both sets of charts are shown to encompass results of the fringe cases of no power output (0th percentile) and maximum power output (100th percentile).
The pattern for these curves is similar across sites, with wind power (Farm 1) producing higher power for more time than each consecutive addition of wave power capacity up to the 100% wave power system (Farm 5). On the East Coast, Farm 5 wave power produces no power more time (16.33%) than Farm 1 wind power (3.66%), but this can be reduced to 1.71% of the time for any of the combined systems. The opposite is true of the West Coast, where Farm 5 wave power produces no power less time (0.21%) than Farm 1 wind power (4.83%), and this can be reduced to just 0.07% of the time for any of the combined systems. At the Hywind site, Farm 5 wave power produces no power for a similar amount of time (5.17%) as Farm 1 wind power (3.45%), but this can be reduced to 0.65% for any of the combined systems. Thus, all regions produce power for a greater share of time by using a combined system, but the relative time spent producing no power is significantly greater for wave power on the East Coast, slightly greater for wind power on the West Coast, and just barely higher for wave power at the Hywind site.

Farm 1 produces the maximum farm capacity (24 MW) more than all other farm layouts for all regions. It produces the maximum power 10.46% of the time on the East Coast and 9.09% of the time on the West Coast, compared to 36.04% of the time at the Hywind site. This is reflected in the maximum power spike observed in the Farm 1 probability density function in Figure 4.3, which is greatest for the Hywind site. The amount of time of maximum power production is consistently higher for the Farm 1 wind system than for the Farm 5 wave system or any combined system across all regions. On the East Coast, Farm 1 wind power produces maximum power more time (10.46%) than Farm 5 wave power (0.50%), and this proportion decreases slightly to 0.39% for any of the combined systems. This closely resembles performance on the West Coast, where Farm 1 wind power produces maximum power 9.09% of the time, compared to 0.04% for Farm 5 wave power or 0.03% for any of the combined systems. For the Hywind site, Farm 1 wind power produces maximum power a much higher percentage of time (36.04%) than either Farm 5 wave power (0.43%) or the combined systems (0.43%). The decrease in time spent producing maximum power for combined systems is expected, as it is less likely that both wind and wave power would operate at full capacity at the same time, thus decreasing the time spent producing the total farm capacity. The much higher percent of time spent producing close to maximum power at the Hywind site is likely due
to favorable wind conditions during the winter season of data collection at the Hywind Scotland site, whereas the percent of time spent producing maximum power for both wave power and combined systems is similar across regions. Overall, wind power and wind-dominated combined systems tend to produce power for more time than wave-dominated layouts, but West Coast wave power alone produces fewer hours of no power output than wind power alone, indicating the particularly favorable wave conditions on the West Coast compared to other regions. The reduction in the percent of time producing no power for combined systems across all regions decreases the amount of idle time with no power generation, although it is possible that only minimal power is produced at some of these additional times of power production. This indicates the potential benefit of ensuring that some power is sent to the electric grid, even in minimal quantities, for more time of the year in a combined wave-wind system.

Analysis of hourly power distributions using summary statistics, qualitative comparison, Kolmogorov-Smirnov testing, and the percent of time producing certain amounts of power gives an indication of the relative amount of power produced by each farm layout for each region. An additional metric is needed to quantify power variability relative to power production. The hourly coefficient of variability, defined as the standard deviation normalized by the mean, provides a metric for comparing the overall power variability of different farm layouts across regions:

$$CV_{\text{hourly}} = \frac{\sigma_{\text{hourly}}}{\mu_{\text{hourly}}}$$

(4.3)

where $\sigma_{\text{hourly}}$ is the standard deviation of hourly capacity factors and $\mu_{\text{hourly}}$ is the mean of hourly capacity factors.
Figure 4.11 Hourly coefficients of variability across farm types and regions

Note the high variability of all wind and wave systems, with $CV_{\text{hourly}} > 0.5$ for all layouts. Each site exhibits different behavior across farm types. The East Coast site has a relatively consistent coefficient of variability for Farm 1 (0.7751), Farm 2 (0.7628), and Farm 3 (0.7726), which then increases significantly for Farm 4 (0.8556) and Farm 5 (1.1750), the latter having a standard deviation greater than the mean and thus a $CV_{\text{hourly}}$ greater than 1. Wind power is less variable on the East Coast than wave power, so variability increases as more wave capacity is added. The West Coast site has the lowest $CV_{\text{hourly}}$ for the 25%-75% combined system Farm 4 (0.5732). The coefficient of variability increases slightly for Farm 5 (0.5966), but increases more significantly as more wind capacity is added in Farm 3 (0.6208), Farm 2 (0.6937), and Farm 1 (0.7703). It appears that wave power is less variable on an hourly basis than wind power on the West Coast, but that variability is minimized by a couple of percentage points with the combined system Farm 4. The Hywind site exhibits a slightly different pattern, with its lowest $CV_{\text{hourly}}$ for Farm 3 (0.6328) and a very similar value for Farm 2 (0.6353). Variability is slightly higher for Farm 1 (0.6600) and Farm 4 (0.6930), and increases significantly for Farm 5 (0.9030). Thus, wave power is more variable at the Hywind site than wind power, but the combined system Farm 3 (50% wind, 50% wave) achieves the lowest coefficient of variability. However, this is only slightly lower than it is for Farm 1 (100% wind) or Farm 2 (75% wind, 25% wave). These results indicate the potential to
reduce variability of power output by combining wind and wave energy, but also show key differences in the overall, hourly variability of wind and wave power across the US East Coast, West Coast, and Scottish North Sea. Additional correlation and variability analysis on other time scales is conducted to investigate these trends further.

**Chapter 4.1.2 Correlations**

The correlations of wind and wave power output and met-ocean conditions lend further insight into the variability of offshore wind, wave, and combined wave-wind farms. Correlation between wind speed and wave height and between wind power and Pelamis wave power are analyzed at identical hours and at an increasing time lag of up to 40 hours. The Pearson correlation \( r \) is typically used for normally distributed data, but can be used for large sample sizes and as a descriptive statistic of the correlation (Bonnini et al. 2014). The Pearson correlation is also used by Stoutenburg et al. (2010).

![Figure 4.12 Wind speed and wave height correlation across sites. “r” is the Pearson correlation coefficient and “acf” is the cross-correlation at time lag “tau.” The maximum correlation and its time lag are indicated by the blue diamond and red lines.](image-url)
The East Coast and Hywind sites exhibit similar strongly correlated wind speed and wave height, indicating well-correlated wind and wave resources and dominance of wind waves rather than swell. The East Coast Comprehensive site shows its strongest correlation between wind speed and wave height in real time (lag equal to 0), with a Pearson’s correlation coefficient $r = 0.669$. This indicates less than favorable conditions for a combined system to reduce power variability, as the wind and wave resources are strongly correlated in real time. Thus, wave height (and wave power) increase almost instantly when wind speed (and wind power) increases and vice versa, so both energy sources produce power at the same time. This correlation coefficient is similar to the lagged Hywind correlation with $acf = 0.687$ at a lag of 3 hours, but the lagged correlation at the Hywind site may improve the potential for a combined system to reduce power variability. Although wave height (and power) increases when wind speed (and power) increases and vice versa, it typically occurs at a 3-hour lag. This delayed response can be utilized to smooth power output when the wind speed dies down but the correlated wave height is still increasing up to 3 hours later.

It is important to note that behavior of the comprehensive site does not always mimic behavior of specific sites on the East Coast. For example, Station 44018 on the East Coast has a similar, strong correlation of $acf = 0.694$ as the East Coast Comprehensive site, but at a lag of 3 hours.

![Figure 4.13 Wind speed and wave height correlation for East Coast Station 44018 and West Coast Station 46013](image)

Such a site would be more suitable for combined wave-wind projects since this lagged correlation minimizes combined power output variability, even if this is not the case for
the East Coast generally. This indicates that there can be variability of lagged correlation analysis between sites within a given region, though in this case the value of the correlation coefficient is fairly consistent between the specific site and the example site even when the time lag changes. The West Coast comprehensive site has a much lower correlation compared to the East Coast and Hywind site. The strongest correlation between wind speed and wave height on the West Coast is seen at a lag of 1 hour, with an $acf = 0.451$. This is similar to the example West Coast Station 46013 (Figure 4.13), which has an $acf$ of 0.471 at a lag of 4 hours. Like on the East Coast, the lag appears to vary somewhat between the specific stations and the example station while the correlation coefficient value is fairly similar. The lower correlation and 1-hour lag on the West Coast indicate the region’s particular suitability for combined wave-wind systems to reduce power variability, as swells likely comprise a larger portion of waves on the West Coast.

Despite the higher correlation between wind speed and wave height observed at the Hywind Scotland site and on the East Coast, correlation magnitude between wind power and Pelamis wave power is fairly consistent across all three sites.
All three regions exhibit a moderate correlation coefficient of around 0.5; the East Coast has $r = 0.499$ with no lag, the West Coast has $acf = 0.529$ with a lag of 1 hour, and the Hywind site has $acf = 0.523$ with a longer lag of 5 hours. The time lag is consistent with the correlation lag between wind speed and wave height for the East Coast and West Coast, but increases by 2 hours at the Hywind site from 3 hours to 5 hours. Note that the magnitude of the correlation is approximately the same across the three regions, with the primary difference driven by the time lag $tau$. Although the correlation between wind power and Pelamis wave power may be similar across regions, different time lags would lead to different power variability of combined systems. The greater the time lag of correlation between wind power and Pelamis wave power, the less variable a combined system should be. However, it is important to note the variation of this time lag between results from example stations and the comprehensive regions.
The magnitude of the correlation is approximately the same between the example sites in Figure 4.15 and their respective regional comprehensive sites in Figure 4.14, but the time lag changes considerably. While there is no correlation lag for the East Coast Comprehensive site, there is a lag of 5 hours with $acf = 0.555$ for Station 44018. Similarly, the lag increases from 1 hour to 7 hours between the West Coast Comprehensive site and Station 46013, and $acf$ decreases from 0.529 to 0.474. If the main difference between wind power and Pelamis wave power correlation across regions is the time lag, then significant variability of the time lag within a particular region yields less conclusive results. For example, although the East Coast Comprehensive site appears to have well-correlated wind power and Pelamis wave power in real-time, Station 44018 exhibits a higher lag of 5 hours. Still, comprehensive sites allow for regional comparison of average results, even if individual stations from each region yield different results. Regional comparison indicates that wind power and Pelamis wave power are moderately correlated in real-time for the East Coast Comprehensive site, at a lag of 1 hour for the West Coast Comprehensive site, and at a lag of 5 hours for the Hywind site. This would likely lead to less power variability for an integrated system at the Hywind site, followed by the West Coast and then by the East Coast.

With different results and trends for the different correlations considered (wind speed and wave height and wind power and Pelamis wave power), it is difficult to definitively state the magnitude or lag of the correlation between wind and wave resources in these regions. These differences are likely due to the power matrix of the
Pelamis WEC, which defines power outputs for specific rounded wave heights and wave periods. This rounding may dilute the linear correlation between wind power and wave power. Similarly, the nonlinear equations for wind power as a function of wind speed cubed (Equation 2.2) and wave power as a function of wave height squared (Equation 2.4) may diminish the linear correlation between wind power and Pelamis wave power. Thus, correlation between wind speed and wave height is used as the best characterization of the correlation of wind and wave resources, though it is important to also consider the results of both correlation analyses. Based on this first type of analysis, it appears that the East Coast and Hywind site typically exhibit stronger correlation between wind and wave resources compared to the West Coast (Figure 4.8). This would indicate that the West Coast would exhibit the least variability of an integrated wave-wind energy system of the three regions considered, corroborating the previous results shown in Figure 4.11. Additionally, the 3-hour lag at the Hywind site may enable reduced power variability of combined systems despite the stronger correlation.
Chapter 4.1.3 Inter-annual Variability

It is important to understand possible variation of power production from year to year. Inter-annual variability is examined for sites on the US East and West Coasts where longer data records are available.

Figure 4.16 Annual average capacity factors

There does not appear to be significant inter-annual variability of annual average capacity factor for any farm layout. The capacity factor changes each year as is expected for a variable resource, but is fairly consistent overall. This inter-annual variability is quantified by the inter-annual coefficient of variability $CV_{annual}$:

$$CV_{annual} = \frac{\sigma_{annual}}{\mu_{annual}}$$

(4.2)

where $\sigma_{annual}$ is the standard deviation of annual average capacity factors and $\mu_{annual}$ is the mean of annual average capacity factors. This metric takes an average of data that has already been averaged on an annual time-scale, introducing some bias into the results compared to the coefficient of variability for hourly data $CV_{hourly}$. However, this metric can still be used to isolate variability across years for a given site or region.
In general, $CV_{\text{annual}}$ increases across farm types for the East Coast (Figure 4.17). Farm 1 has the lowest $CV_{\text{annual}}$ for the East Coast Comprehensive site of 0.0591, which increases significantly as more wave energy capacity is added. This is mainly driven by the reduction in the mean capacity factor, the denominator in Equation 4.2. For the East Coast Comprehensive Farm 5, there is a $CV_{\text{annual}}$ of 0.2614; this means that the annual standard deviation for Farm 5 is 26.14% of the mean annual capacity factor for the East Coast Comprehensive site, while it is just 5.91% for Farm 1. These results differ slightly for Station 44018, which shows lower variability overall but the same general trend, and a lower $CV_{\text{annual}}$ for Farm 2 than for Farm 1. On the West Coast, annual variability is lowest for Farm 3 with equal wind and wave capacity, with a $CV_{\text{annual}} = 0.0564$. This increases if you move in either direction, but seems to increase at a faster rate by adding more wave capacity and moving towards Farm 5, with $CV_{\text{annual}} = 0.1515$. Overall, it
appears that wave energy has a higher inter-annual variability on both the East Coast and the West Coast. Inter-annual variability is fairly low for systems comprised of at least half wind capacity (Farm 1, Farm 2, and Farm 3).

**Chapter 4.1.4 Seasonal Variability**

Seasonal variability provides an indication of the typical differences of power variability across seasons, particularly between winter and summer months. Analysis by Stoutenburg et al. (2010) shows typically higher wind and wave power on the US West Coast during the winter and lower wind and wave power during the summer. Seasonal variability is examined for sites on the US East and West Coasts where longer data records are available than at the Hywind Scotland site.

![Figure 4.18 Monthly average capacity factors for comprehensive regional data](image)

The monthly average capacity factor for each farm layout at the regional comprehensive sites is shown in Figure 4.18 for the entire time period and for a sample year. In general, monthly average power is higher for farms with more wind capacity than wave capacity,
which is intuitive based on the shapes of the probability distributions of wind and wave power in Chapter 4.1.1. This can be seen in greater detail in the sample year data of Figure 4.18, which shows Farm 1 consistently higher than all other farms, followed by Farm 2, then Farm 3, Farm 4, and Farm 5. This is not to say that wave power capacity factor never exceeds wind power capacity factor, but that the monthly average capacity factor is higher for wind power than for wave power. These results are consistent with the regional representative years, which average all data across all years on a monthly basis into one year of monthly average capacity factors.

The representative years with monthly average capacity factors (Figure 4.19) are very similar to the sample years shown in Figure 4.16. On the East Coast, wind and wave resources are seasonally correlated, with higher capacity factors in the winter and lower capacity factors in the summer. The seasonal variability appears to be higher for wind power than wave power. East Coast Farm 1 has a winter capacity factor maximum of 0.5623 and summer minimum of 0.2200, while Farm 5 has a winter maximum of 0.2071 and summer minimum of 0.0612. This trend is progressively true for Farm 2, Farm 3, and Farm 4, with wind-dominated combined systems more seasonally variable than wave-dominated combined systems.

On the West Coast, wind and wave resources follow a similar, but lagged, seasonal trend. West Coast wind power exhibits its highest capacity factor in the spring and early summer (March, April, May, and June) with a maximum of 0.5011, followed by lowest capacity factor in the early fall (September, October, November) with a
minimum of 0.3190. Wave power follows a different seasonality, with highs in the winter and early spring (December, January, February, and March) and maximum capacity factor 0.3154, and lows in the summer and early fall (July, August, and September) and minimum capacity factor 0.1798. This is consistent with results from Stoutenburg et al. (2010), who reported highest wind power in June and lowest in September and highest wave power in December and lowest in August. Like on the East Coast, capacity factor varies across a larger range over the course of a year for wind power than wave power. These trends are progressively true for combined systems Farm 2, Farm 3, and Farm 4 as well.

Seasonal variation is more closely aligned on the East Coast than on the West Coast. Wind and wave power follow the same seasonal trend on the East Coast, whereas West Coast wind power peaks in the spring and early summer and is lowest in the early fall while wave power peaks in the winter and early spring and is lowest in the late summer and early fall. This indicates a more closely seasonally correlated wind and wave resource on the East Coast than on the West Coast. The temporal shift in the seasonal pattern of West Coast wind and wave power may be advantageous for combined systems that can utilize combined resources to reduce seasonal variability.

The seasonal variability can be quantified using a monthly coefficient of variability:

$$CV_{\text{monthly}} = \frac{\sigma_{\text{monthly}}}{\mu_{\text{monthly}}}$$  \hspace{1cm} (4.3)

where $\sigma_{\text{monthly}}$ is the standard deviation of monthly average capacity factors and $\mu_{\text{monthly}}$ is the mean of annual average capacity factors. The $CV_{\text{monthly}}$ is calculated for the representative year of monthly average data. Despite a greater range of capacity factors for wind power than wave power in both regions, the $CV_{\text{monthly}}$ value is greater for wave power than wind power on the East Coast and approximately the same on the West Coast (Figure 4.20, Farm 5).
The monthly coefficient of variability is actually very similar for all farm layouts in both regions. While standard deviation decreases the more wave capacity is added, the mean capacity factor also decreases, thereby lowering the coefficient of variability proportionally. On the East Coast, Farm 1 has $CV_{\text{monthly}} = 0.3260$, which increases slightly across farm types so that Farm 5 has $CV_{\text{monthly}} = 0.3796$. This is only a 5% increase in the monthly standard deviation relative to the mean, however. The West Coast has a less seasonally variable resource for all farm layouts. Farm 1 has $CV_{\text{monthly}} = 0.1656$, which decreases slightly as wave capacity is added until Farm 3, which has $CV_{\text{monthly}} = 0.1421$. This again increases slightly for Farm 4 with $CV_{\text{monthly}} = 0.1436$, and for Farm 5 with $CV_{\text{monthly}} 0.1656$. However, the lower 50%-50% split farm only has a 2% decrease in seasonal variability compared to the periphery cases of Farm 1 and Farm 5. These trends follow the overall trend of inter-annual variability across farm layouts (Figure 4.17) with two distinct differences. First, the values of monthly variability are consistently higher for both regions than inter-annual variability, with the exception of the more annually variable wave energy resource that dominates Farm 4 and Farm 5 in Figure 4.17. Second, the actual differences between monthly coefficients of variability are much smaller than the differences observed between annual coefficients of variability across farm layouts. This indicates that each farm layout is more seasonally variable than annually variable, but that variability across farm types is less prominent seasonally than annually.
Chapter 4.1.3 Diurnal Variability

Diurnal variability is the hourly variability over the course of a day. Understanding diurnal variability of power output is particularly important for power producers and grid operators, as it is needed for planning the energy needs of the electric grid for intermittent sources like wind energy and wave energy. Diurnal power output can vary drastically depending on the wind and wave conditions on any given day.

![Graphs showing diurnal variability](image)

Figure 4.21 Hourly average capacity factor over one sample day

Randomly selected sample days for the East Coast Comprehensive, West Coast Comprehensive, and Hywind sites exhibit this variability well (Figure 4.21). There is no discernible pattern to hourly power output for the randomly selected days, and sampling other days would yield entirely different results for each site. The West Coast Comprehensive sample day shows how wind and wave resources can vary significantly over the course of the day. On this particular day, wave power (Farm 5) has a much
smaller variation of capacity factor between 0.2 and 0.6, compared to wind power (Farm 1) which varies from a capacity factor of 0.0 between hours 1:00am-5:00am and 1.0 between 12:00pm-5:00pm. Farm 5 (wave) capacity factor is higher than Farm 1 (wind) capacity factor in the morning but lower in the afternoon and evening, demonstrating how the different resources can produce power at different times of the day. In this case, wave power is fairly consistent throughout the day but decreases slightly in the afternoon, whereas wind power fluctuations from no production in the early morning to maximum production in the early afternoon.

Averaging across all days in each regional data set creates a representative day with hourly average day that can be used to analyze the typical diurnal variability.

This enables more standardized diurnal variability results. The plots in Figure 4.22 show the representative, or average, day using hourly data for each site; the actual power output for any given site on any given day never behaves in such a uniform way. Still, the
representative days can be used to assess typical diurnal variability trends and compare between sites. The West Coast appears to have the highest wind power variability (Farm 1) over the course of the day. Wind power has the highest capacity factor of 0.4809 in the middle of the night at 1:00am, slowly decreasing to a low of 0.3472 at 5:00pm before sharply increasing again after 6:00pm. Wave power (Farm 5) exhibits very little variability throughout the day, though there may be a slightly lower capacity factor during the evening from 3:00pm-8:00pm than during the morning between 5:00am-10:00am. The diurnal pattern observed for wind speed is also true for Farm 2, Farm 3, and Farm 4, each to a less extent due to the decreasing wind capacity and increasing wave capacity across farm layouts.

There is very little diurnal variability on the East Coast, even for wind power alone. While there is some variation that follows a similar trend to the West Coast Farm 1, it is to a much lesser extent and power output is more consistent. Overall, the East Coast exhibits very little variability for both wind and wave resources, and subsequently for combined systems as well. For farm layouts with more wind capacity, particularly Farm 1 (100% wind) and Farm 2 (75% wind, 25% wave), the West Coast capacity factor is considerably more variable than on the East Coast. The high capacity factors for these farm layouts are greater than the typical East Coast capacity factor but the low capacity factors are also less than the typical East Coast capacity factor, indicating the greater West Coast diurnal variability. By contrast, East Coast Farm 1 and Farm 2 exhibit relatively consistent power output over the course of the representative day, at a value in the mid-range of the more variable West Coast capacity factor. The Hywind site exhibits a similar pattern of diurnal variability, or lack thereof, to the US East Coast. The West Coast trend of higher wind power in the middle of the night and lower wind power in the early evening is not seen at the Hywind site. Power is relatively consistent diurnally for all Hywind farm layouts, though there is a slight decrease in wave power in the early morning between 3:00am-5:00am for higher wave power capacity, particularly Farm 5 (100% wave) and Farm 4 (25% wind, 75% wave).
The diurnal variability is quantified using the diurnal coefficient of variability:

\[ CV_{\text{diurnal}} = \frac{\sigma_{\text{diurnal}}}{\mu_{\text{diurnal}}} \]  

where \( \sigma_{\text{diurnal}} \) is the standard deviation of hourly average capacity factors for a representative day and \( \mu_{\text{diurnal}} \) is the mean of hourly average capacity factors for a representative day. The \( CV_{\text{diurnal}} \) is calculated for a representative day of hourly data averaged across all days for all sites in a region, shown in Figure 4.21.

As expected, West Coast \( CV_{\text{diurnal}} \) is significantly greater than for the East Coast and Hywind sites, with the exception of Farm 5 where the Hywind \( CV_{\text{diurnal}} \) is greatest. This makes sense based on Figure 4.22, which shows higher West Coast variability for Farm 1, Farm 2, Farm 3, and Farm 4 compared to other sites, but a relatively low variability for Farm 5. The Hywind site also appears to have its greatest variability for the Farm 5 layout. For both the East Coast and West Coast site, diurnal variability decreases progressively from Farm 1 to Farm 5 as more wind capacity is replaced with wave capacity. The Hywind site \( CV_{\text{diurnal}} \) decreases from Farm 1 to Farm 3, but then increases again for Farm 4 and increases even more for Farm 5, indicating the benefit of a 50%-50% combined system for reducing diurnal variability at the Hywind site. The diurnal variability for onshore wind farms is typically much greater due to the diurnal surface heating cycle. The results here indicate that the weaker diurnal atmospheric stability cycle over water surfaces results in much more consistent wind and less variable power prediction compared to onshore wind when results are averaged across many days.
Chapter 4.2 Environmental Loading

Wind and wave loading are examined for the spar-buoy floating offshore wind turbine. Wind loading is investigated using the analytical solutions to the spar-buoy rotational spring-damper equation. Wave loading is analyzed using linear wave analysis of Morrison’s equation and CFD simulation results of a wave passing through a spar-buoy wind turbine.

Chapter 4.2.1 Wind Loading Results

The effect of wind loading on the spar-buoy can be characterized with the equations described in Chapter 3.3.1. Several assumptions about the turbine dimensions are required for this analysis. The model assumes a buoy radius of 7 m and a turbine and foundation mass of 12,000 tonnes, or 12,000,000 kg. The mass is concentrated at the ballast point, which is also the center of gravity such that the moment of inertia $I = mL_G^2$. It assumes a total length $L = 176.6$ m, with a submerged length $L_{\text{submerged}} = 78$ m and hub height $L_{\text{hub}} = 98.6$ m. It assumes a fixed point halfway up the submerged length such that $L_{\text{fixed}} = 39$ m, a center of gravity at the base of the buoy such that $L_G = 39$ m, and a center of buoyancy $\gamma_5$ of the submerged length such that $L_B = 62.4$ m – 39 m = 23.4 m. It also assumes an initial pitch angle $\theta_0 = 0^\circ$ and initial angular velocity $\omega_0 = 0 \text{ rad/s}$. Finally, it assumes a wind drag coefficient $C_D = 0.85$, air density $\rho_{\text{air}}$ of 1.184 kg/m$^3$, and rotor swept area $A$ of 18,600 m$^2$. These assumptions can be refined and computed exactly if the design of the system is available.

The steady state pitch angle $\theta_{ss}$ is determined for a range of wind speeds using Equation 3.11.
The steady state pitch angle increases quadratically with wind speed up to the nominal wind speed of 13 m/s. For these assumptions, $\theta_{ss} = 3.16^\circ$ at $v_{nominal} = 13$ m/s. This is relatively low and is below the $8^\circ$-$14^\circ$ of pitching observed by NREL for a smaller spar-buoy prototype (Matha et al. 2011). Beyond the nominal wind speed, the turbine blades would themselves be pitched to keep power production at the rated capacity, thereby approximately stabilizing the force on the turbine and consequently the pitch angle at $3.16^\circ$. This is shown by the dotted black line in Figure 4.24. Without this blade pitching, the turbine pitching angle would continue to increase quadratically, eventually reaching $11.54^\circ$ at $v_{cutout} = 25$ m/s.

The minimum damping coefficient for critical damping and overdamping $D_{critical}$ is calculated using Equation 3.15. Note that $D_{critical}$ depends only on the moment of inertia of the turbine and buoy system, the buoyant force, buoyant length, gravitational force, and gravitational length. It is affected by the assumptions used for the buoyant and gravitational lengths and submerged volume, but is independent of the wind speed. Using Equation 3.15, we find:

$$D_{critical} = 2\sqrt{1.8252e10 \, kg \cdot m^2 \cdot (120,499,487 \, N \cdot 23.4 \, m + 117,720 \, N \cdot 39 \, m)}$$

$$D_{critical} = 368,192,062.9 \, \frac{kg\cdot m^2}{s}$$
This is a large damping coefficient but is reasonable given the very large mass (12,000,000 kg) of the system. At the damping coefficient of $D = D_{\text{critical}}$, oscillation of the spar-buoy system is critically damped.

Figure 4.25 Spar-buoy pitch oscillation with critical damping

Figure 4.25 shows behavior of a critically damped spar-buoy subjected to a constant wind force due to constant wind speed $u = v_{\text{nominal}} = 13$ m/s. The critically damped system reaches the steady state $\theta_{ss} = 3.16^\circ$ almost immediately ($t \ll 1s$). This is beneficial for the system as it reaches the steady state rapidly, but the sudden, almost instantaneous shift in angle could mechanically stress the system.

If we assume an arbitrary damping coefficient greater than $D_{\text{critical}}$, then the spar-buoy behaves like an overdamped oscillator.
Figure 4.26 shows the behavior of an overdamped spar-buoy subjected to the same environmental loading as Figure 4.25 but with a higher damping coefficient ranging from $2D_{\text{critical}}$ to $20D_{\text{critical}}$. For a damping coefficient closer to the critical damping coefficient, such as $2D_{\text{critical}}$, the overdamped system approaches $\theta_{ss} = 3.16^\circ$ in a similar but slower manner as the critically damped system. This is also true of larger damping coefficients such as $5D_{\text{critical}}$, $10D_{\text{critical}}$, and $20D_{\text{critical}}$ but at a progressively slower rate. As the damping coefficient increases, it takes longer for the overdamped system to reach the steady state pitch angle. An overdamped system is likely ideal for stabilizing the spar-buoy from wind loading, as the system quickly reaches steady state within a few seconds but does not pitch as suddenly as the critically damped system.

If we assume an arbitrary damping coefficient less than $D_{\text{critical}}$, such that $D = 0.1D_{\text{critical}}$, then the spar-buoy behaves like an underdamped oscillator as it approaches the steady state for a constant wind load.
Figure 4.27 depicts the oscillating behavior of the underdamped system subjected to the same environmental loading at the nominal wind speed. While the buoy does reach $\theta_{ss} = 3.16^\circ$ within around 4 s, it moves beyond this steady state angle to a $\theta_{max} = 5.47^\circ$. The fluctuation decreases as time progresses due to the damping of the system, but at early times the turbine rotates past the steady state angle by decreasing amounts. This would almost certainly cause the turbine to enter its own turbulent wake, thereby decreasing turbine efficiency. It would also cause mechanical stress on the system as the turbine rocks back and forth before it reaches steady state, and is not ideal behavior for a spar-buoy floating wind turbine under wind loading.

These results all assume a constant wind load. When the time-variant wind speed and wind force is factored in, as well as different initial conditions for the initial angle $\theta_0$ and angular velocity $\omega_0$, complex behavior can ensue. This is particularly true for the underdamped system, which would oscillate with different amplitudes depending on the wind force and damping coefficient. Thus, it is important to design a system that behaves like either an overdamped or critically damped harmonic oscillator. The damping coefficient $D$ should be at least equal to the critical damping coefficient $D_{critical} = 2\sqrt{I_{buoy}/\tau_{buoy}}$. The damping coefficient can be controlled in the design of floating foundations, and is dependent on the hydrodynamic properties of the design and thus the
geometry of the system. Damping in this case is provided by the resistance of the water to the structure’s movement; the system loses energy equivalent to the force exerted on the water multiplied by the speed of the fluid-structure interface. Thus, a less hydrodynamic design yields higher dissipation. A larger damping coefficient of at least $D_{\text{critical}}$ is required to ensure that the system is critically damped or overdamped when pitching due to wind loading. This can be achieved by designing the spar-buoy structure to increase the frictional interaction with the water and thus achieve the required damping to minimize wind-induced pitching.

**Chapter 4.2.2 Wave Loading Results**

Wave loading on a spar-buoy turbine is analyzed to determine the potential use of the shadow effect for decreasing wave loading on wind turbines and improving operations and maintenance logistics. An initial wave with wave height $H = 10$ m and wave period $T = 5$ s is analyzed. Subsequent waves with diminishing wave heights are examined based on the percent of wave power extracted by a wave energy converter, as shown in Table 3.8. Six waves are examined with heights 10 m, 9.5 m, 8.9 m, 8.4 m, 7.7 m, and 7.1 m corresponding to wave energy extraction of 0%, 10%, 20%, 30%, 40%, and 50%. The wave force on a structure 8 m away is determined using Equation 3.17 (Morrison’s equation).

Several important assumptions were made and wave parameters calculated in order to apply Morrison’s equation. Force was examined for a spar-buoy with diameter $D = 14$ m in water depth $h = 50$ m. The force was calculated at the water surface such that $z = 0$ m. The wavelength $\lambda$ was calculated as $50*H$ for the initial wave height $H = 10$ m in order to satisfy the linear wave minimum assumption that $\frac{H}{\lambda} \leq \frac{1}{50}$; thus, $\lambda = 500$ m and $k = \frac{2\pi}{\lambda} = 0.0126$. This $\lambda$ is well above 5*D = 70 m required for the Morrison equation. The diffraction parameter $d_f$ was calculated as 0.088 using Equation 3.21B, and is also below the maximum value of 0.5 required for the Morrison equation. $u_0$ is calculated using these parameters and Equation 3.22, enabling the calculation of the Keulegan-Carpenter number $KC$ with Equation 3.21A. However, for the assumed wave heights and conditions the $KC$ value is consistently below the required $KC \gg 6 \ (KC = 4.03, 3.82, 3.60, 3.37, 3.12, \text{ and } 2.85 \text{ for the wave heights considered})$, indicating that Morrison’s equation is
not ideal for calculating the force of this wave. Still, Morrison’s equation can be applied as a basis for comparison of the wave force on a spar-buoy structure for different wave heights. Based on the low KC numbers, the model assumes a drag coefficient $C_d = 1.0$ and inertial coefficient $C_m = 2.0$ (McCormick 2010).

![Morrison's Wave Force at x = 8 m](image1)

**Figure 4.28 Morrison’s wave force at x = 8 m**

Figure 4.28 shows the wave force for the wave heights considered in Table 3.8 at a distance 8 m away from the start of the wave. The force varies in time with a period of $T = 5$ s, so the local wave force on the structure changes direction every half-period (2.5 s) as the wave passes by the structure. Note how the successive decreases in wave height due to wave power extraction lead to lower wave forces. The amplitude of the force equation decreases as the wave height decreases, shown in Figure 4.29.

![Force Amplitude vs. Wave Height Reduction](image2)

**Figure 4.29 Wave force amplitude decreases as wave height decreases**

A 30% decrease in wave height that corresponds to a 50% conversion of wave power decreases the wave force amplitude by 30% from 177,708.4 kN to 125,658.8 kN. Note that the amplitude of the wave force decreases linearly with a 1:1 ratio with wave height.
reduction. This is a substantial decrease of the force the wave imparts on a structure located 8 m away, indicating the significant benefit the shadow effect may have on reducing wave loading of offshore wind turbines.

The Morrison’s equation wave load results are further investigated using CFD analysis in SimScale of the pressure on a spar-buoy wind turbine due to the same-sized waves. Figure 4.30 shows the propagation of the base case wave in the SimScale model.

Figure 4.30 CFD base case wave propagation. Time progresses by 1 s for each panel, across rows. Water is shown in red (phase 1) and the air is shown in blue (phase 0). The wave is defined as \( H = 10\text{m} \) above the mean sea level, and propagates throughout the fluid domain for the 8 s simulation. Note how by the time \( t = 8\text{s} \) in the last panel, the wave has developed into two crests along the fluid surface.

The initial wave setup in Figure 4.26 is located 8 m upstream of the wind turbine (not shown) to replicate the setup of the Morrison equation force calculation. This also enabled the wave setup to develop into a wave that resembles the behavior of an ocean wave by the time it reaches the turbine 8 m away. As the wave passes by the turbine, it imparts a pressure on the turbine foundation. The normalized pressure \( p_{\text{rgh}} \), which subtracts the hydrostatic pressure from the wave pressure, is shown in Figure 4.31.
SimScale CFD results yielded negative normalized air pressure values shown in blue for all figures, which were rescaled to zero. The magnitude of the maximum negative pressure was added to all pressures for each wave height CFD simulation to normalize the results to the surface pressure. The pressure scales shown in the color bars in Figure 4.27 were then rescaled to match the color bar of the $H = 10$ m (0% power extraction) base case. The base case indicates a pressure gradient from the base of the spar-buoy foundation that increases towards the water surface. The wave pressure on the foundation is maximum just below the water surface and in the front of the turbine where the wave
collides with the structure. Pressure rapidly decreases in the thin green band at the water surface, and is normalized to zero for the portion of the turbine above sea level. This gradient also exists for the 10%, 20%, and 30% power extraction cases ($H = 9.5$ m, $8.9$ m, and $8.4$ m) but to a lesser extent. The maximum pressure for these turbines decreases compared to the base case, indicating the effect of WEC power extraction on decreasing the wave pressure (and force) on the turbine. The pressure decreases further for the 40% and 50% power extraction cases ($H = 7.7$ m and $7.1$ m) making the pressure gradient even less apparent. Between the Morrison’s equation force calculation and the CFD results, it is apparent that WEC power conversion has the ability to decrease the significant wave height of incoming waves, thereby decreasing the wave loading on floating offshore wind turbines.
Chapter V. Discussion and Conclusions

Combining offshore wind farms with wave energy farms can provide benefits for both systems through reduced power variability and the shadow effect. These results are regionally and locally specific, however, making integrated systems more beneficial in some locations than others. Power variability decreases for combined systems on all time-scales except diurnally on the West Coast. The hourly coefficient of variability is the best metric considered for overall variability, and is lowest for the West Coast for the Farm 4 system. Farm 3 exhibits the lowest coefficient of variability for both seasonal and inter-annual variability on the West Coast. These results indicate the potential benefits of combined offshore wind and wave energy systems on the West Coast for reducing power variability. The Hywind hourly variability is also lowest for one of the combined systems, Farm 3, and is followed closely by Farm 2. Thus, combining wind and wave power generation has the potential to reduce the overall variability on both the West Coast and at the Hywind site. Either the Farm 3 (50% wind, 50% wave) or Farm 4 (25% wind, 75% wave) layout is most ideal for variability reduction on the West Coast, whereas either Farm 2 (25% wind, 75% wave) or Farm 3 is ideal at the Hywind site. While combined systems may generally decrease power variability for certain regions, it is necessary to look at the particular region or site to determine the ideal capacity breakdown of wind and wave power.

These benefits are not observed to as great an extent on the East Coast, where seasonal and inter-annual variability increase as more wave capacity is added, although some reductions in variability are still achieved. Although Farm 2 has the lowest hourly variability on the East Coast, the coefficient of variability is only slightly below Farm 1, indicating insignificant reduction in variability for combined systems on the East Coast. However, diurnal variability does decrease as more wave capacity is installed, indicating the possibility of some reduction in diurnal variability by implementing combined systems. These results are largely corroborated by the correlations observed between wind speed and wave height in each region; the West Coast has the lowest correlation between wind speed and wave height, and achieves the greatest reductions in power variability for combined systems. Thus, it appears that West Coast waves have more
swells and fewer wind-waves than the other regions, leading to the lower correlation of the resources and reduced variability for the Farm 3 and Farm 4 systems. Despite a high correlation between wind speed and wave height at the Hywind site comparable to the East Coast, the Hywind site also exhibits reduced power variability for combined systems, particularly Farm 2 and Farm 3. This is likely due to the 3-hour lag in the wind speed and wave height correlation in the North Sea. Although the resources are well-correlated and the wave field at the Hywind site likely has a significant proportion of wind-waves rather than swells, the wind and wave resources are correlated at a great enough lag that combined systems can still reduce the power variability. It is not only the magnitude of the wind and wave resource correlation that is important for predicting potential reductions in power variability of combined systems, but also the time-scale at which the correlation occurs.

Although combined systems decrease power variability on the West Coast and at the Hywind Scotland site more than on the East Coast, it is necessary to consider the overall reduction in power output that accompanies this decreased power variability. While Farm 2, Farm 3, and Farm 4 may decrease power variability at the Hywind and West Coast sites, they also decrease the mean power output compared to the 100% wind farm. Distributions of wind power and wave power demonstrate why average power output decreases as more wave capacity is added to combined systems; wind power produces close to its maximum power output significantly more than wave power. This may partially be a function of the Pelamis WEC analyzed being less than suitable for the typical sea states observed in these regions; the results may differ as more efficient wave energy converters are developed for application in specific regions and sea states. Still, results indicate significant reduction in mean and third quartile power output for combined systems (and 100% wave power). The relative decrease in power output must be considered in conjunction with decreases in power variability for combined wind and wave systems. This analysis examines combined wind and wave systems as a percentage of a set farm capacity of 24 MW. This enables standardization of results for each farm type for comparative analysis, but also juxtaposes wind and wave energy in an either-or scenario. By adding wave capacity, we are forced to reduce wind capacity in this analysis, while this may not be the case in the actual implementation of a combined
system. Instead, it can be beneficial to think of how wave energy can be added to an existing offshore wind farm as a way to decrease the power variability (and actually increase the overall power output), particularly where no more wind power can be installed. For example, wave power could be added near wind turbines in a wind farm that is already densely packed, as the wave power generation does not interfere with wind power production. This would be suitable for sites where no further wind turbines could be installed efficiently without experiencing significant wake losses. In this case, wave power capacity could be added to existing or planned wind power capacity rather than replacing it, thus decreasing the total power variability without decreasing the amount of power produced. This concept of additionality of wave power with offshore wind, rather than substitution, makes wave power a compelling supplement to offshore wind farms to reduce power variability on the West Coast and at the Hywind Scotland site. When faced with the choice of adding more wind power capacity or wave power capacity, project developers can utilize additional wave power to still increase the total farm output (less than adding more wind power capacity, however) while also decreasing the overall power variability and smoothing the power output. This can be particularly beneficial at existing, densely-packed offshore wind farms where future wind development is limited due to spatial limitations and wake effects.

Environmental loading plays a significant role in the design of floating offshore wind turbines, and wave energy converters may provide key benefits to reducing some of these loads. The shadow effect can be utilized to decrease wave heights by extracting wave power before waves reach the floating offshore wind turbine structure. The magnitude of the force and pressure that the wave imparts onto a spar-buoy decreases as the wave height is reduced by a WEC. This result indicates several benefits of combined wave-wind systems; the impact of waves on a floating substructure can be reduced through the implementation of WECs, and the reduced wave height can also improve accessibility for operations and maintenance. It is important to note, however, that for floating structures like the spar-buoy the foundation movement is driven by wind loading rather than wave loading. Thus, combining WECs with offshore wind turbines are more likely to benefit the spar-buoy design by improving accessibility rather than reducing foundation motion from wave loading, as this is already minimal. The shadow effect may
better suit other floating foundations that are subject to more wave-induced motion, and warrants further study for floating foundations like the semi-submersible and tension leg platform concepts.

Further analysis of power variability would include specific site comparisons across regions. The results of this thesis indicate different power variability of combined offshore wind and wave farms for different regions, but analyzes these disparities for average sites. Future work could study these power variability and output differences for particular sites in each of these regions and compare specific case studies. Sites could also be grouped by other parameters that may affect power variability, such as depth, distance from shore, or particular geographic features. Power variability could also be studied further using the concept of additionality of wave power capacity to existing offshore wind farms rather than substitution, examining the extent to which adding wave capacity to existing offshore wind farms affects variability. This can be done by assuming a wind farm capacity or using a specific wind farm case study, and incrementally adding wave farm capacity. Note that variability would have to be normalized to the new total farm capacity in such a study. This would enable further analysis of the reduction of power variability of combined wave-wind systems through additional, rather than substitutional, wave capacity.

There is significant future work to examine the shadow effect of wave energy converters and its potential benefits to floating offshore wind turbines. CFD analysis can be conducted that factors in the wave-structure two-way interaction to more accurately model how a turbine is expected to move due to wave loading. This could be done for any of the spar-buoy, semi-submersible, or tension leg platform concepts, as well as new floating platform designs. Future work could also investigate the optimal spatial arrangement of different types of wave energy converters to maximize the benefits of this shadow effect. CFD models could analyze the effects of multiple WECs on a large wave field with multiple ocean waves approaching the wind turbine to determine the effects of WEC spatial arrangement on the shadow effect.

Offshore wind power and wave power both present extensive opportunities for the implementation of clean, renewable energy that can contribute to worldwide goals of minimizing the effects of climate change. Their shared location in the marine
environment enables combining or collocating wind power and wave power farms, which can reduce the power variability of these time-variable energy sources, though this effect is both site-specific and regionally-driven. Combined wave-wind systems have the potential to reduce power variability on the US West Coast and at the Hywind Scotland site in the North Sea. On average, this effect is not achieved on the US East Coast, where the wind and wave resources are more correlated in real-time. However, this may not be strictly true of all sites on the East Coast, and opportunities may arise for combined system benefits at particular sites. Likewise, combined systems may not prove beneficial to all potential sites on the US West Coast or in the Scottish North Sea, but in general power variability is reduced the most for combined systems in these regions. The physical benefits of the shadow effect of wave energy converters would also prove beneficial at any of these sites and regions. As more offshore wind projects are implemented in the US, UK, and worldwide and wave energy conversion continues to develop, marine renewable energy technologies can take advantage of their shared ocean environment in combined wave-wind systems that offer key benefits to both individual technologies.
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Appendix A: Wind Loading Equations

\[
I \frac{d^2 \theta}{dt^2} + D \frac{d\theta}{dt} + (F_B L_B + F_G L_G) \theta = F_W L_W \tag{3.12D}
\]

\[
\lambda_{1,2} = \frac{-D \pm \sqrt{D^2 - 4I\tau_{buoy}}}{2I} \tag{3.13}
\]

**Case 1. Critical Damping**

\[
D^2 - 4I\tau_{buoy} = 0 \tag{3.14A}
\]

\[
D_{critical} = 2\sqrt{I\tau_{buoy}} \tag{3.15}
\]

\[
\lambda_{1,2} = \frac{-D}{2I}
\]

\[
\theta_H = c_1 e^{-\frac{D}{2t}t} + c_2 te^{-\frac{D}{2t}t}
\]

\[
\theta_p = \frac{\tau_{wind}}{\tau_{buoy}}
\]

\[
\theta(t) = c_1 e^{-\frac{D}{2t}t} + c_2 te^{-\frac{D}{2t}t} + \frac{\tau_{wind}}{\tau_{buoy}}
\]

\[
\theta'(t) = \frac{-D}{2I} c_1 e^{-\frac{D}{2t}t} + \frac{-D}{2I} c_2 te^{-\frac{D}{2t}t} + c_2 e^{-\frac{D}{2t}t}
\]

\[
\theta_0 = c_1 + \frac{\tau_{wind}}{\tau_{buoy}}
\]

\[
c_1 = \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}}
\]

\[
\omega_0 = \frac{-D}{2I} c_1 + c_2
\]

\[
c_2 = \omega_0 + \frac{D}{2I} \left( \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}} \right) = \omega_0 + \frac{\sqrt{I\tau_{buoy}}}{I} \left( \theta_0 - \frac{\tau_{wind}}{\tau_{buoy}} \right)
\]

\[
\theta(t) = c_1 e^{-\frac{\sqrt{I\tau_{buoy}}}{I}t} + c_2 te^{-\frac{\sqrt{I\tau_{buoy}}}{I}t} + \frac{\tau_{wind}}{\tau_{buoy}} \tag{3.16A}
\]
Case 2. Overdamping

\[ D^2 - 4I \tau_{buoy} < 0 \] (3.14B)

\[ \theta_H = c_1 e^{-D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t + c_2 e^{D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t \]

\[ \theta_p = \frac{\tau_{wind}}{\tau_{buoy}} \]

\[ \theta(t) = c_1 e^{-D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t + c_2 e^{D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t + \frac{\tau_{wind}}{\tau_{buoy}} \]

\[ \theta'(t) = \frac{-D + \sqrt{D^2 - 4I \tau_{buoy}}}{2I} c_1 e^{-D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t + \frac{-D - \sqrt{D^2 - 4I \tau_{buoy}}}{2I} c_2 e^{D\sqrt{D^2 - 4I \tau_{buoy}}/2I} t \]

\[ \theta_0 = c_1 + c_2 + \frac{\tau_{wind}}{\tau_{buoy}} \]

\[ c_2 = \theta_0 - c_1 - \frac{\tau_{wind}}{\tau_{buoy}} \]

\[ \omega_0 = \frac{-D + \sqrt{D^2 - 4I \tau_{buoy}}}{2I} c_1 + \frac{-D - \sqrt{D^2 - 4I \tau_{buoy}}}{2I} c_2 \]

\[ \omega_0 = \frac{-D + \sqrt{D^2 - 4I \tau_{buoy}}}{2I} c_1 + \frac{-D - \sqrt{D^2 - 4I \tau_{buoy}}}{2I} (\theta_0 - c_1 - \frac{\tau_{wind}}{\tau_{buoy}}) \]

\[ \omega_0 = \frac{-Dc_1}{2I} + \frac{c_1 \sqrt{D^2 - 4I \tau_{buoy}}}{2I} - \frac{D\theta}{2I} - \frac{\theta_0 \sqrt{D^2 - 4I \tau_{buoy}}}{2I} + \frac{Dc_1}{2I} + \frac{c_1 \sqrt{D^2 - 4I \tau_{buoy}}}{2I} \]

\[ \omega_0 = \frac{c_1 \sqrt{D^2 - 4I \tau_{buoy}}}{2I} + \frac{D\tau_{wind}}{2I \tau_{buoy}} + \frac{\tau_{wind} \sqrt{D^2 - 4I \tau_{buoy}}}{2I \tau_{buoy}} - \frac{\theta_0 \sqrt{D^2 - 4I \tau_{buoy}}}{2I \tau_{buoy}} - \frac{D\theta}{2I} \]

\[ c_1 = \frac{\theta_0}{2} - \frac{\tau_{wind}}{2\tau_{buoy}} + \frac{\omega_0}{2 \sqrt{D^2 - 4I \tau_{buoy}}} + \frac{D\theta_0}{2 \sqrt{D^2 - 4I \tau_{buoy}}} - \frac{D\tau_{wind}}{2 \sqrt{D^2 - 4I \tau_{buoy}}} \]

\[ c_2 = \theta_0 - c_1 - \frac{\tau_{wind}}{\tau_{buoy}} \]

\[ c_2 = \frac{\theta_0}{2} - \frac{\tau_{wind}}{2\tau_{buoy}} - \frac{\omega_0}{2 \sqrt{D^2 - 4I \tau_{buoy}}} - \frac{D\theta_0}{2 \sqrt{D^2 - 4I \tau_{buoy}}} + \frac{D\tau_{wind}}{2 \sqrt{D^2 - 4I \tau_{buoy}}} \]
\[ \theta(t) = c_1 e^{-\frac{D + \sqrt{D^2 - 4I\tau_{buoy}}}{2I}t} + c_2 e^{-\frac{D - \sqrt{D^2 - 4I\tau_{buoy}}}{2I}t} + \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \] (3.16B)

Case 3. Underdamping

\[ D^2 - 4I\tau_{buoy} > 0 \] (3.14C)

\[ \theta_H = c_1 e^{\frac{-D}{2I}t} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + c_2 e^{\frac{-D}{2I}t} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \]

\[ \theta_p = \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \]

\[ \theta(t) = c_1 e^{\frac{-D}{2I}t} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + c_2 e^{\frac{-D}{2I}t} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \]

\[ \theta'(t) = -c_1 e^{\frac{-D}{2I}t} \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \]

\[ - \frac{Dc_1}{2I} e^{\frac{-D}{2I}t} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \]

\[ + c_2 e^{\frac{-D}{2I}t} \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \]

\[ - \frac{Dc_2}{2I} e^{\frac{-D}{2I}t} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \]

\[ \theta'(t) = \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \left( -c_1 \frac{\sqrt{-D^2 + 4I\tau_{buoy}} - Dc_2}{2I} e^{\frac{-D}{2I}t} \right) \]

\[ + \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) \left( c_2 \frac{\sqrt{-D^2 + 4I\tau_{buoy}} - Dc_1}{2I} e^{\frac{-D}{2I}t} \right) \]

\[ \theta_0 = c_1 + \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \]

\[ c_1 = \theta_0 - \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \]

\[ \omega_0 = c_2 \sqrt{-D^2 + 4I\tau_{buoy}} - Dc_1 = \frac{c_2 \sqrt{-D^2 + 4I\tau_{buoy}} - D(\theta_0 - \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}})}{2I} \]

\[ c_2 = \frac{2I \omega_0 + D(\theta_0 - \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}})}{\sqrt{-D^2 + 4I\tau_{buoy}}} \]

\[ \theta(t) = c_1 e^{\frac{-D}{2I}t} \cos \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + c_2 e^{\frac{-D}{2I}t} \sin \left( \frac{\sqrt{-D^2 + 4I\tau_{buoy}}}{2I} t \right) + \frac{\tau_{\text{wind}}}{\tau_{\text{buoy}}} \] (3.16C)