Shared Mooring Systems for Deep-Water Floating Wind Farms

Final Report

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Abstract

This project explored the feasibility of shared mooring lines to lower the cost of floating wind farms in deep water. These unconventional floating array configurations feature mooring lines that run directly between adjacent turbines, reducing the number of anchors. A novel shared-mooring floating wind array design was developed and optimized. State-of-the-art modeling tools were expanded to allow simulation of the couplings created by shared mooring lines. Simulations showed that the shared lines caused no resonance issues and gave favorable characteristics in line-failure events. The optimized array design was analyzed in comparison to a baseline array design that featured conventional, individual mooring lines. The results demonstrate how shared mooring systems can reduce overall mooring system material and installation costs, thereby improving the feasibility and lowering the cost of wind farms in deep waters.

Keywords

Offshore wind, wind farm, floating wind array, deep water, mooring system, design, shared mooring.

Acknowledgments

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Acronyms and Abbreviations

AOP	annual energy production
CapEx	capital expenditure
DEA	drag embedment anchor
DLC	design load case
DTU	Denmark Technical University
kWh	kilowatt hours
LCOE	levelized cost of energy
m	meters
m/s	meters per second
MBL	minimum breaking load
MN	meganewton
MW	megawatt
MWh	megawatt hour
kN	kilonewton
NREL	National Renewable Energy Laboratory
NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OpEx	operational expenditure
S	seconds
t	metric tonne
W	watts

Executive Summary

The project *Shared Mooring Systems for Deep-Water Floating Wind Farms* explored the feasibility of inter-turbine mooring lines to lower the cost of floating wind farms in deep waters. Shared mooring systems feature mooring lines that run directly between adjacent turbines, reducing the number of anchors in a floating wind farm. The project developed and optimized a first-of-its-kind shared-mooring floating wind array, and then conduct an analysis comparing it to a baseline array featuring conventional, individual mooring systems. The results demonstrate how shared mooring systems can reduce overall mooring system material and installation costs, thereby improving the feasibility and lowering the costs of wind farms in deep waters.

Conceptual Design

A systematic process for preliminary design of shared mooring systems was developed, combining linear optimization at the array level with nonlinear mooring component-level optimization. The process accounts for various constraints and design considerations, including ensuring that quasi-static loads are within recommended safety factors for mooring lines and anchors. The design process was successfully applied to a wide variety of shared-mooring array layouts in the process of seeking a conceptual design.

A staggered linear array of 10 turbines with 9 shared mooring lines was found to be the best-performing array layout after considering over 40 options. The chosen layout couples the turbines together sequentially with alternating perpendicular shared lines to minimize propagation of coupling effects through the array. Taut polyester mooring lines were found to be the most cost effective for this configuration. The anchor lines use suction piles to support the vertical loads. The shared lines feature two clump weights to tune the restoring properties.

The conceptual design meets all constraints and performance goals, as analyzed with the current quasi-static models, and is estimated to have a similar cost to an equivalent individually moored array design. However, the shared-mooring design also supports shared anchors, which can introduce significant cost reductions to this array layout.

Modeling Tool Development

Shared mooring systems are known to have unique system dynamic behaviors due to the mechanical coupling between floating platforms caused by the shared mooring lines. A capability for modeling this coupling did not previously exist in state-of-the-art floating wind simulation tools. NREL's OpenFAST modeling suite, including FAST.Farm for array simulation, was modified to provide the required new capabilities.

HydroDyn, the hydrodynamics model in FAST.Farm, was modified to simulate the propagation of waves across a floating wind farm. This allows the timing of the wave loads on the floating platforms to be accurately accounted for, which provides accurate relative motions between turbines so that tensions on shared mooring lines are estimated properly.

MoorDyn, the mooring system dynamics model in FAST.Farm, was modified to operate across all turbines in the array and to allow coupling between each of the floating platforms. This change required significant restructuring to the time stepping routines in FAST.Farm and was essential for allowing simulation of the coupling effects caused by shared mooring lines.

Together, the two improvements to FAST.Farm allow accurate coupled simulation of floating wind farms with shared mooring lines for the first time. The model improvements are publicly available on GitHub.

Design Refinement and Cost Analysis

Using the new FAST.Farm modeling capability, the shared mooring design was analyzed across a range of load cases representative of U.S. West Coast conditions. Mooring system design constraints were checked, and the mooring system design was iteratively adjusted and reevaluated until achieving a final design that minimized mooring system cost while satisfying all technical constraints. A similar optimization process was undertaken for a conventionally moored array with three lines per turbine to provide a baseline for comparison.

A loads comparison of the shared-mooring and baseline designs showed that the shared mooring system did not introduce problematic responses. In fact, it had significantly better performance in the event of mooring line failures, with much smaller offsets than a conventional three-line mooring system. A comparison of the costs shows that the shared-mooring design reduces the total mooring system costs from between 3% to 34% depending on whether shared anchors are used and whether comparing to a three- or four-line baseline design. The shared mooring system also has significantly fewer anchors, reducing disturbance on the seabed. These findings demonstrate the feasibility and significant cost-saving potential of shared mooring systems.

1 Introduction

The project *Shared Mooring Systems for Deep-Water Floating Wind Farms* explored the feasibility of using shared mooring lines—which run directly between adjacent platforms—to lower the cost of floating wind farms in deep water. A shared mooring arrangement sees mooring lines in the interior of the farm running directly between adjacent floating platforms, rather than running to anchors. This reduces the number of mooring lines reaching the seabed, thus reducing total mooring material, and reduces the number of anchors used by the farm. It also enables a reduction in per-turbine mooring line and anchor requirements as the number of turbines in the farm increases. However, shared mooring lines add complexity to a floating wind farm by creating couplings between the floating turbines. Little was known about how to design these mooring arrangements or how they would affect the system performance. To answer these questions, the project developed and optimized a shared-mooring floating wind turbine array design, then evaluated its performance and cost relative to conventional mooring system approaches. In doing so, it assessed how shared mooring systems could reduce overall stationkeeping system material and installation costs, thereby lowering the levelized cost of energy (LCOE) of wind farms in deep waters.

1.1 Background

Stationkeeping system component and associated installation processes are a significant cost and technical challenge to deep-water floating wind farms. In deeper waters, longer mooring lines are required and anchor installations can be more difficult, increasing stationkeeping costs and raising the LCOE. Anchor layout can also become more challenging due to the potential for interference between adjacent turbines' moorings. As such, the total wind farm stationkeeping system cost and design complexity increases with both water depth and farm size.

Sharing stationkeeping components among floating wind turbines in an array is one means of reducing the stationkeeping system cost. As illustrated in Figure 1, sharing components can take the form of shared anchors or shared mooring lines. Shared anchors see multiple floating wind turbines moored to common anchor points, meaning a given anchor may have multiple lines attached. Shared moorings see mooring lines running directly between adjacent floating turbines, bypassing anchoring in these locations.

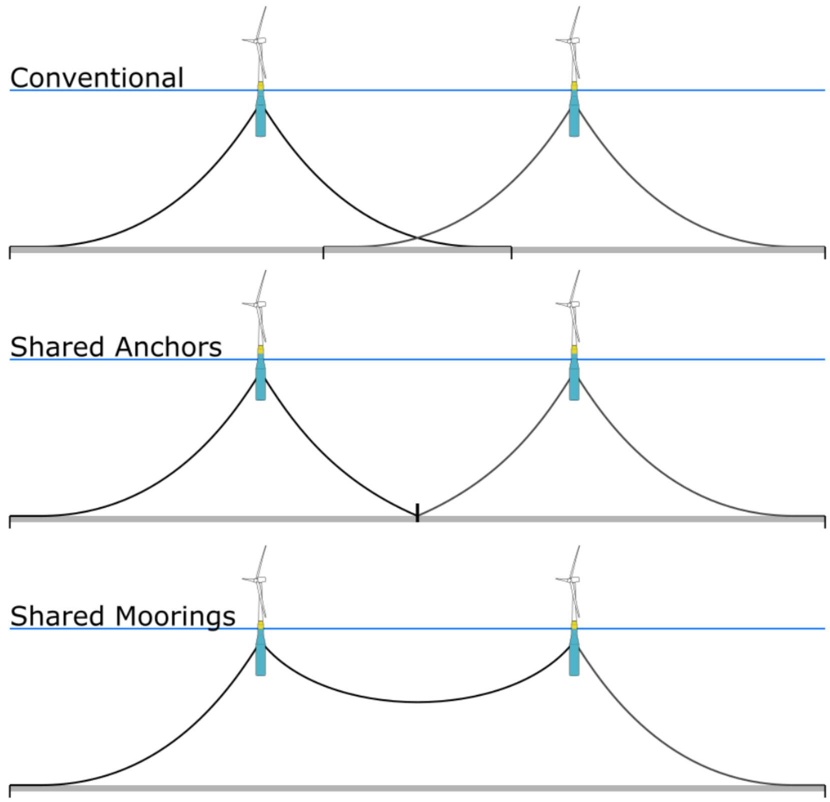


Figure 1. Individual moorings, shared anchors, and shared mooring lines

Existing literature on shared stationkeeping systems is limited. Research on shared anchors, where a single anchor serves mooring lines to multiple turbines, was pioneered by Fontana et al. [1]. They explored how this multiline anchor approach could reduce the number of anchors required for a wind farm and also potentially reduce the magnitude of anchor loads, depending on the choice of layout and mooring configuration. For shared mooring lines, Goldshmidt and Muskulus [2] simulated three different prototypical shared mooring farms, each with three to five turbines, and explored how the number of turbines affects the accumulation of thrust loads in the upwind mooring lines of the farm. In the first study focused on shared-moorings design, Connolly and Hall [3] did a parametric analysis of three pilot-scale shared-mooring floating wind farm designs over a range of water depths and found significant cost savings at depths greater than 500 m.

Other work has looked at the coupled dynamics of shared mooring systems. Hall and Connolly [4] created a preliminary dynamic modelling capability and analyzed a four-turbine, four-anchor array under stochastic wind and wave conditions. This study found that the relative magnitude of the extreme and fatigue mooring loads was significantly reduced by using a shared rather than individual mooring configuration. More recently, Liang et al. [5] studied the restoring and dynamic response characteristics of a two-spar array with one shared line and four anchor lines. While these studies provide initial thoughts on shared mooring arrays, none provide guidance on the design process or promising shared mooring designs at the desired scale for this project.

At the time of writing, one floating wind project is under development that features shared stationkeeping system components. It is the Hywind Tampen array, with 10 turbines and shared anchors. This will also be the largest floating wind farm built once it is completed.

1.2 Project Approach

To shed light on the feasibility and potential benefits of shared mooring systems, this project pursued the preliminary design and optimization of a floating wind farm of similar scale to the Hywind Tampen array, but instead featuring shared mooring lines and designed for the deeper waters found off the U.S. West Coast. The project was arranged to explore the potential of shared mooring systems through development of a conceptual design under specific conditions and comparing that design with a conventional, individually-moored floating array under the same conditions.

The project was organized into three tasks (Figure 2), with Task 1 developing the conceptual design, Task 2 improving the dynamics modeling tools to support shared-mooring arrays, and Task 3 using the updated modeling tools to refine and evaluate the shared-mooring design.

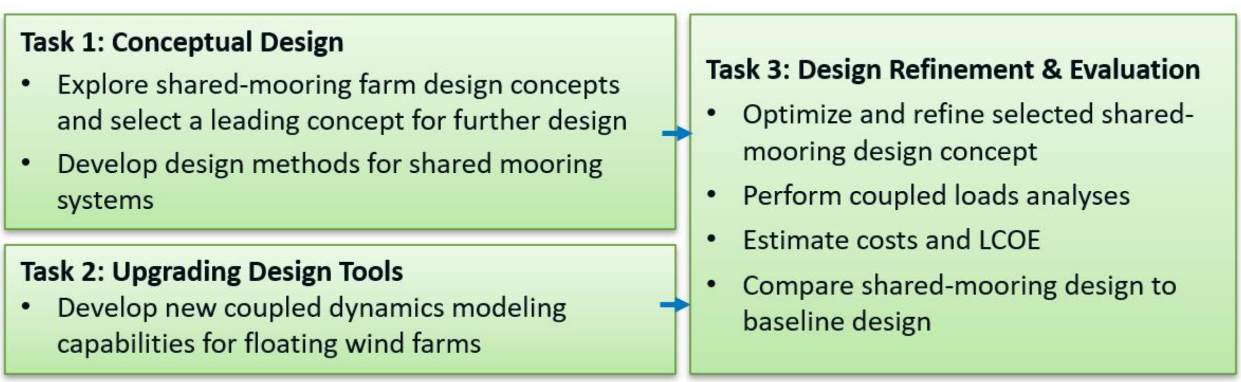


Figure 2. Project tasks

The project made extensive use of open-source software tools—including FAST.Farm, OpenFAST, MoorDyn—and a range of new models and scripts that were created during the project in the Python programming language. All software developments that were taken to an adequate level of maturity for sharing with others have been made publicly available through NREL's GitHub online platform. A new library for quasi-static analysis of mooring systems, MoorPy, was developed in large part from the project and is available at https://github.com/NREL/MoorPy [6].

1.3 Design Basis

The project used assumptions about the site conditions, the farm size, and the floating wind turbine designs to form the basis for the mooring design work. The site conditions were chosen to be representative of a deep-water site on the U.S. Pacific coast with a depth of 600 m. The target array size was 100 MW, with individual 10 MW turbines on spar floating platforms similar to those of Equinor's Hywind design. The mooring systems were designed to allow a mean offset of at most 60 m, 10% of the water depth, to ensure compatibility with dynamic power cables. The strength of the mooring lines and anchors was set according to the guidelines in API RP-2SK [7].

1.3.1 Array Size and Site Conditions

The project site conditions are based on the Bureau of Ocean Energy Management (BOEM) Humboldt call area, near Humboldt Bay in California. This is also a location that was previously studied by NREL for offshore wind (Figure 3). The depth in this area ranges up to 870 m [8] and it is relatively well characterized for offshore wind purposes, with information about wind and wave conditions from nearby locations available.

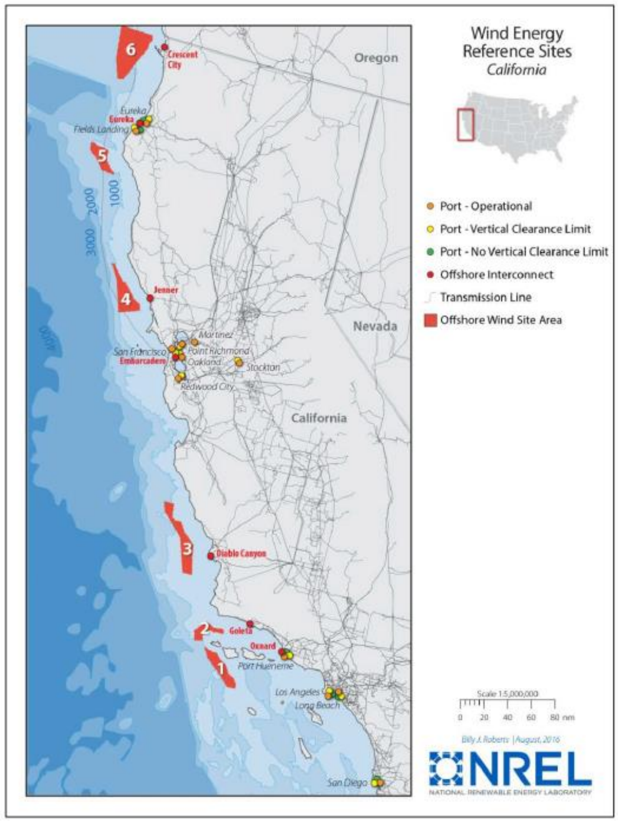


Figure 3: Offshore wind reference sites studied off California (this project used site 5)

To reduce the number of variables in later stages of the project, the water depth was simplified to a uniform 600 m, which is within the range of the Humboldt call area. Little information on the seabed soil type is known, but studies of nearby regions suggest that sand or clay is expected, meaning that the conventional anchoring solutions—drag-embedment anchors and suction piles—are applicable.

Metocean data and statistics for near the site are available from several sources. An NREL study at a nearby reference site gives a mean annual wind speed of 9.7 m/s and mean annual significant wave height of 2.7 m [8]. A separate study for wave energy devices in the area provide a thorough characterization of the wave conditions, including 100-year storm condition with significant wave heights of 8–13 m and peak wave periods around 17 seconds [9]. Data from the ERA 5 hindcast database [10], and data from a nearby wave buoy, NOAA Station 46022 [11], were also considered. From these data, load case parameters can be specified based on the probability distributions of wave periods, wave heights, and mean wind speeds. Load cases are discussed more in Section 4.1.

1.3.2 Baseline Floating Wind Turbine

The intention of the baseline floating wind turbine design is to represent a system similar to a 10 MW Hywind spar design, and to serve as a reference point from which to try new mooring system configurations.

The wind turbine selected for use in the project is the DTU 10 MW Reference Wind Turbine [12], which has been used by researchers since 2013 and is well understood. Its key properties are reviewed in Table 1. Of particular importance to the mooring system design is the turbine's peak thrust of 1.5 MN, which poses the dominant load for the mooring system to counteract.

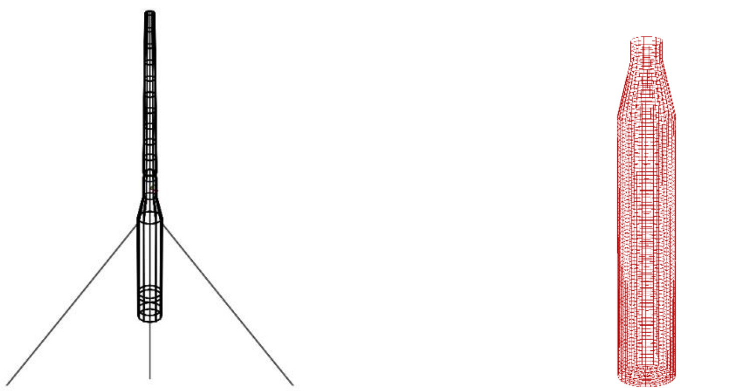
Table 1. DTU 10 MW Reference Wind Turbine properties

Parameter	Value
IEC Wind Class	1A
Rated speed	11.4 m/s
Rated power	10 MW
Peak thrust	1.5 MN
Rated rotor speed	9.6 rpm
Rotor diameter	178.3 m
Hub height	119 m
Shaft tilt angle	5°
Rotor mass	228 t
Nacelle mass	446 t
Tower mass	628 t

The spar-buoy floating substructure was sized specifically for this project. It was first sized using existing spar-sizing tools at NREL and then its ballasting was tuned based on results from steady-state analysis tools with inclusion of the turbine structure and the wind thrust force. The spar is a conventional steel design with internal ballast and a tapered section below the waterline to reduce wave loads. It is based loosely on the proportions of existing Hywind spar designs. It has a draft of 90 m and a diameter of 14.75 m, tapering to an 8 m diameter near the surface. The spar's total displacement is 13,781 m^3 and it has a total mass of 12,510 tonnes. Its overall dimensions and properties are given in Table 2 and it is illustrated in Figure 4.

Table 2. General spar substructure properties

Parameter	Value
Draft	90 m
Freeboard	13 m
Taper depth	5-20 m
Base diameter	14.75 m
Upper diameter	8 m
Displacement	13781 m^3
Steel mass	2024 t
Ballast mass	10,486 t
Center of mass depth	78.2 m



(a) Spar and tower model representation (b) Spar geometry mesh

Figure 4. Baseline spar floating system design

Small ballast adjustments to balance the mooring system weight for different mooring designs were applied throughout the project.

1.3.3 Initial Baseline Mooring System

The initial mooring system for the baseline design was a three-line, semi-taut synthetic system with 150-mm diameter polyester rope and suction-pile anchors spaced at a radius of 656 m from the spar centerline. It is necessary for the spar design to have a bridle attachment to the mooring lines to provide stiffness against yaw motions. As each line approaches the spar, it is split into two separate lines that attach to the spar at spread positions. The attachment depth is 21 m, and the azimuthal location for evenly arrayed mooring lines is set based on the number of mooring lines. For instance, the spacing is 120° for three lines, and 90° for four lines, as shown in Figure 5. This bridle attachment approach provides increased yaw stiffness to compensate for the small moment arm provided by the spar's 7.875 m radius at the fairleads. The attachment radius of the mooring lines was increased later in the project to improve dynamic stability, assuming features protruding from the spar similar to those seen on Hywind designs.

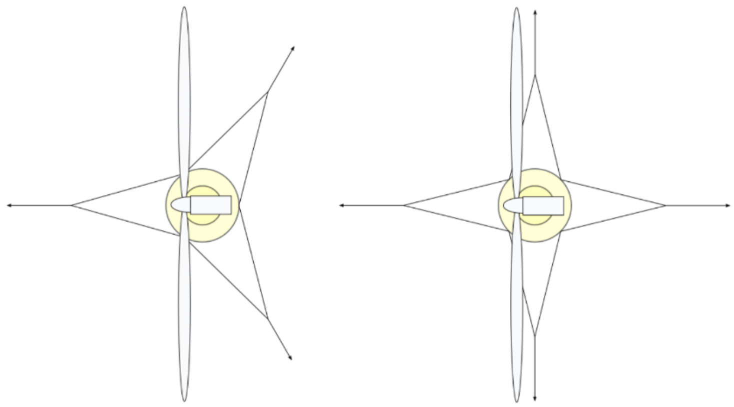


Figure 5. Top view of bridle mooring line attachment to spar for 3- and 4-line systems.

The original mooring design was adjusted later in the project using the same optimization algorithms we used for shared mooring systems to provide a fair basis for comparison of shared-mooring alternatives. Details of the updated baseline mooring system are provided in later sections alongside the properties of the conceptual share mooring system for ease of comparison.

2 Shared Moorings Design Approach

Because of the novelty of shared mooring systems, no applicable design approaches already existed to guide the exploration of shared-mooring concepts for floating wind farms. To fill that gap, this project developed an integrated approach to shared mooring system preliminary design consisting of three processes that work together. As detailed in the following sections, the first process performs an idealized optimization of mooring properties across the array, the second process performs a component-level optimization of each mooring line within the array, and the third process couples the two previous processes together to synchronously optimize both the overall array and its individual mooring lines. Later in this section, cost models used to evaluate the designs are presented and an initial comparison is made of the baseline and shared-mooring designs.

2.1 Linear System-Level Shared-Mooring Optimization

Shared mooring systems create unique additional design challenges compared to conventional mooring systems because of the inter-platform couplings that are introduced. One challenge is accounting for the coupled effect on the floating wind turbines' stationkeeping properties, in terms of their resistance to wind- and wave-induced offsets. The other challenge is ensuring that the design keeps the array in the desired positions in equilibrium.

Both these challenges were addressed by developing a design approach that is based on a linearized model of a shared-mooring floating wind turbine array [13]. This model approximates each mooring's force-displacement properties as linear (an adequate assumption for most situations at the conceptual design stage), which allows efficient methods of adjusting design variables and achieving design requirements. The coupled stationkeeping properties are represented by creating a system-wide stiffness matrix, which represents the horizontal force-displacement relationships of the entire array. This allows direct computation of each turbine's offsets, or watch circles, under loaded conditions.

The most challenging step is ensuring the design provides "layout equilibrium"—being in equilibrium at the desired positions in the absence of external forcing. The complexity of this constraint for shared mooring systems necessitated a novel solution. The methodology incorporates theory from other disciplines into an algorithm that calculates the required ratios of mooring line tensions or weights within the array to achieve the constraint. This significantly reduces the optimization process, so that the least-cost solution can be easily found by comparing different combinations of feasible mooring weight ratios.

This process relies on assumptions about the linearized properties of each mooring within the array, in terms of horizontal tension, horizontal effective stiffness, and weight. These assumptions are handled as inputs, which can be adjusted to account for different mooring line properties. The other input is the array layout, which includes the mooring attachments. The mooring lines are divided into groups based on having identical properties and roles within the array. The process of the linear system optimization is shown in Figure 6. More information about this approach is available in [13].

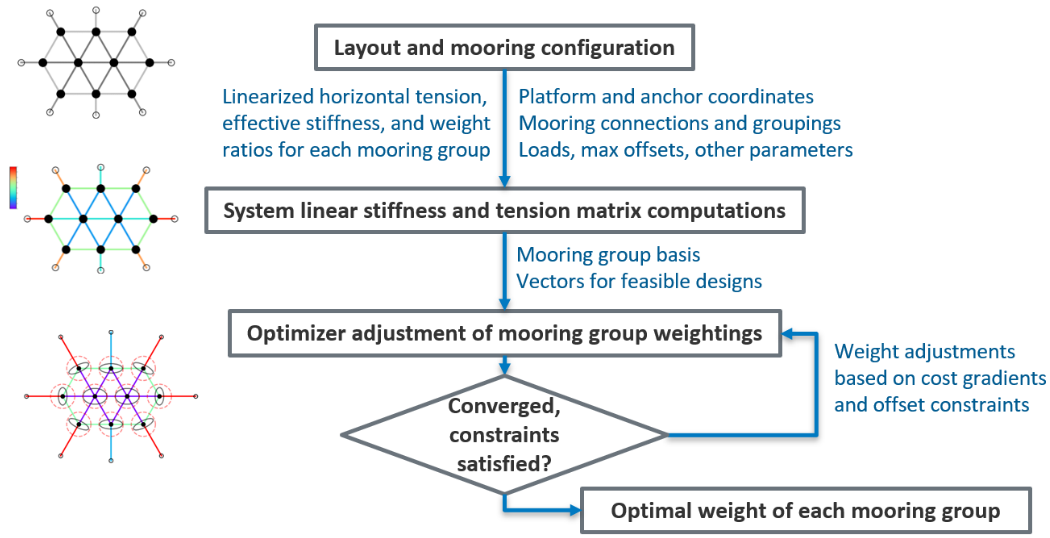


Figure 6: Linear shared mooring system optimization

2.1.1 Array Layout

To best explore the potential of shared mooring systems, a wide variety of array layouts were considered. The target array size is 10 turbines, but layout sizes from 2 turbines up to 13 turbines were explored to capture the range of options that could be most effective. If smaller shared arrays were advantageous, a 10-turbine array could be realized by combining multiple smaller arrays.

To compare layouts fairly, the spacing parameters were fixed. The spacing between turbines in an array is set at 1,600 m, roughly 9 times the assumed rotor diameter. The spacing strikes a balance between wake effects and sprawl, and is the approximate value used in the Hywind Scotland project. Initial layouts used an anchor radius of 1,800 m, which is three times the water depth. Later, anchor spacings were adjusted to best suit the selected layout and mooring arrangement.

An array layout defines the platform and anchor positions, the mooring line attachments between those positions, and the grouping of mooring lines that are to have identical properties. Using a template-based approach for layout generation, over 40 layouts were analyzed for stationkeeping efficiency. A main determinant of stationkeeping efficiency is the roundness of the watch circles. Examples of some of the array layouts considered are shown in Figure 7.

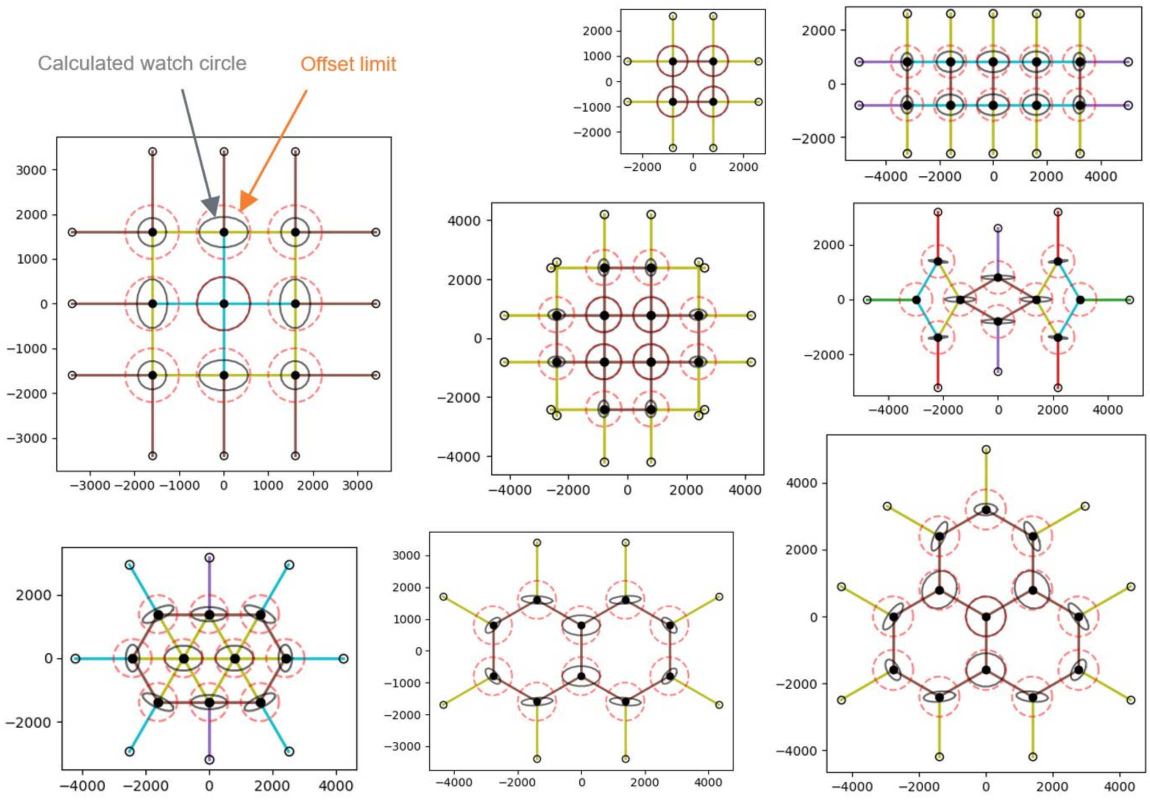


Figure 7. Example array layouts analyzed using the linear method

2.1.2 Selected Array Layout

After performing initial shared-mooring optimizations of the most promising layout concepts and comparing their estimated costs, a 10-turbine layout consisting of two staggered rows of turbines with shared mooring lines that cross back and forth between the rows (Figure 8) was selected. This layout had one of the lowest costs of all arrays considered, and the lowest cost of any 10-turbine arrays. This can be explained by its ability to provide even, omnidirectional stationkeeping (indicated by the round watch circles) for 8 out of ten turbines, meaning the mooring system is very efficient. The other competitive layouts were smaller arrays with only 2–4 turbines, making them less suitable for the desired ~100 MW array design.

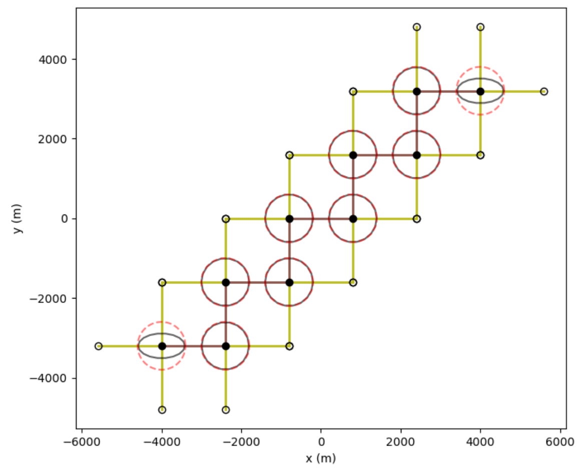
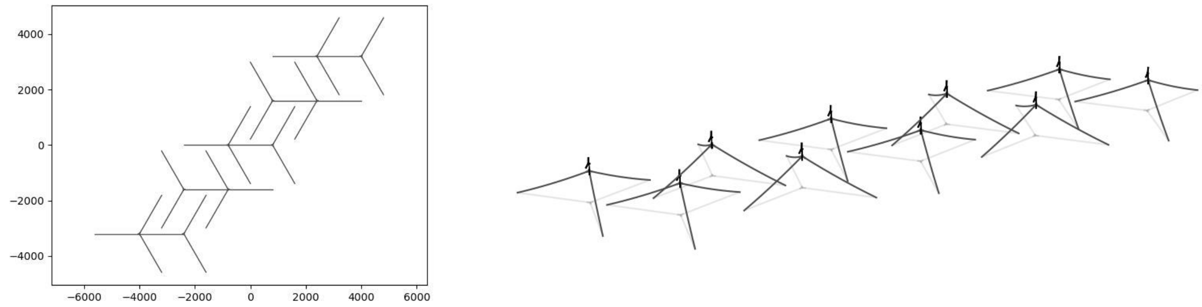


Figure 8: Conceptual shared-mooring array layout

Shared and anchor lines are differentiated by color, and watch circles are shown at 10X magnification.

The shared-mooring array layout had the anchor spacings reduced to 1,600 m to eliminate mooring line overlaps and position pairs of anchors at coincident points. This meant that the layout could utilize shared anchors as well as shared mooring lines, to allow exploration of potential advantages from anchor sharing.

A baseline array layout was also created to match the shared-mooring layout. For comparability, the turbine positions are identical so that the wake effects are equivalent between the baseline and shared-mooring arrays. However, for the three-line mooring systems, the mooring line headings had to be adjusted to avoid interference issues between the mooring lines of adjacent turbines. The baseline array with these adjusted mooring line headings is shown in Figure 9.



(a) Array layout

(b) Array visualization

Figure 9. Baseline array layout showing mooring orientations to avoid interference

2.2 Nonlinear Component-Level Mooring Sizing

Designing physically plausible mooring lines requires nonlinear modeling of the quasi-static behavior of each segment within the mooring line, accounting for weight, elasticity, and seabed contact. Design methods for these are well-established for anchor lines, but not for shared lines. Furthermore, the shared-mooring design methodology developed in this project requires automated sizing scripts that can be called “in the loop” during array-level optimization runs. As such, a solution for nonlinear analysis and sizing of individual moorings was needed.

The model basis for the nonlinear mooring sizing approach is a new quasi-static mooring model developed within this project, MoorPy. MoorPy is a versatile, Python implementation of well-established quasi-static mooring approaches that have been used previously at NREL [14], with additional capabilities to ease array-level mooring analysis and design.

The design optimization basis for the nonlinear mooring sizing approach is an object-oriented mooring line design framework build on top of MoorPy. This framework considers various mooring design parameterizations as well as specific design criteria and constraints. At the top level is an optimization algorithm that is tailored to the mooring design problem, which works in conjunction with the cost models to identify the least-cost sizing of any given mooring arrangement while adhering to technical constraints.

The mooring design framework includes typical mooring arrangements for anchored mooring lines as well as arrangements for shared mooring lines that we selected in this project. An example of an arrangement for a shared mooring with two weights is shown in Figure 10, with the design variables labeled in blue and the constraints labeled in red.

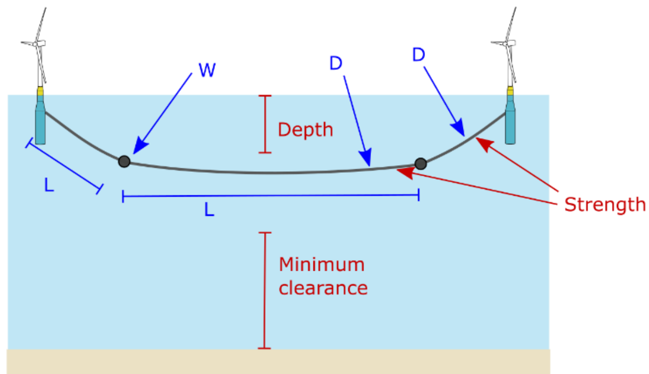


Figure 10: Example mooring arrangement showing design variables (blue) and constraints (red)

The full set of configurations considered in this project, along with their design variables and constraints, are discussed in Sections 2.2.1 and 2.2.3. The cost models used in these mooring optimizations are presented in Section 2.4.

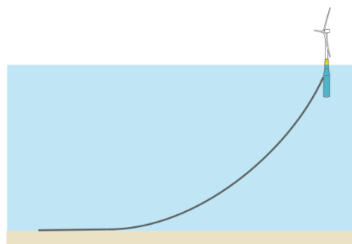
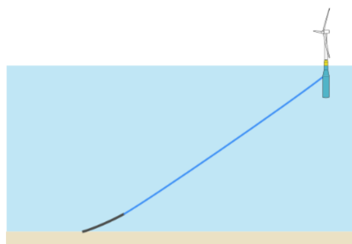
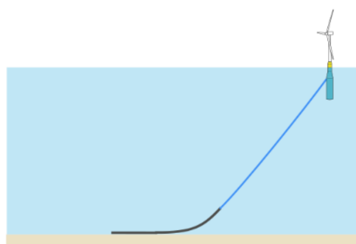
2.2.1 Mooring Configurations

Multiple mooring line arrangements are possible for any given shared or anchored mooring line within an array. The most likely arrangements for anchor lines are well established [15], ranging from all-chain catenary lines to lines that combine chain and wire rope, to lines that consist of synthetic line material with chain only at one or both attachment points.

For this project, the dominant considerations are the overall mechanical properties of the mooring line that impact the stationkeeping response and the need to prevent seabed contact of delicate line materials. In practice, this means that all weight and elasticity factors should be considered when computing mooring line forces, and chain must be used for any line portions that contact the seabed. It is common to also use chain at the tops of mooring lines to facilitate mooring tension adjustment. This upper chain portion is neglected in the current work because short chain segments at the top of mooring lines will have a relatively small impact on mooring system static response and cost. The bridle attachment was not modeled in the mooring sizing optimizations since it will have minimal effect on individual mooring line characteristics. Instead, the bridles were added after the system is sized, for inclusion in the full-system stiffness analysis.

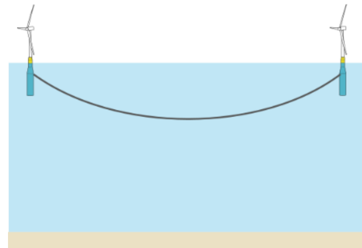
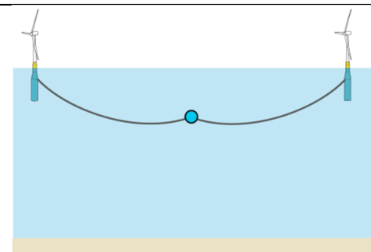
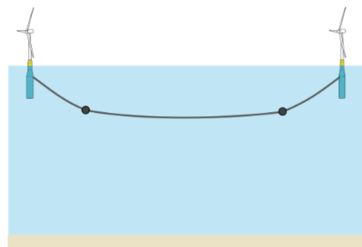
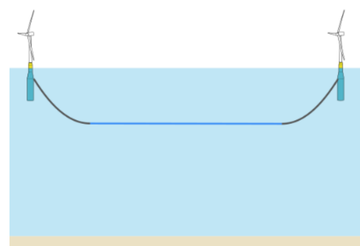
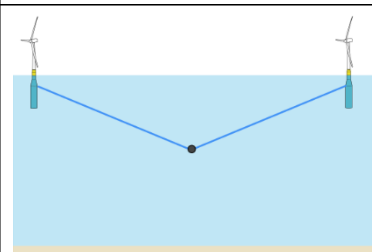
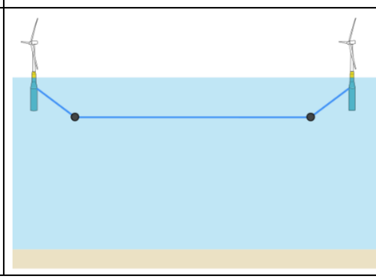
Two anchor types were considered in this stage of the project: drag embedment anchors and suction piles. These represent the most common anchor solutions for floating wind, with drag embedment anchors being the more affordable option suitable for catenary moorings, and suction piles being more expensive option and suitable for semi-taut and taut moorings. Using the two common anchor types provides for a balanced evaluation of shared mooring system performance and cost. The specific anchored mooring line configurations considered in the project are listed in Table 3.

Table 3: Anchored mooring line configuration options

Catenary chain This is a conventional all-chain catenary mooring system, designed to keep some chain on the seabed at all times to avoid vertical anchor loads and allow cost-effective drag-embedment anchor.		Design variables: • Chain size • Chain length • (Anchor spacing)
Taut synthetic rope This is a taut mooring arrangement that gets its compliance from the elasticity of the mooring line (polyester in this case). It has vertical anchor loads so it requires anchors with vertical load capability.		Design variables: • Rope size • Rope length • (Anchor spacing)
Semi-taut chain-rope This is a hybrid arrangement that uses the light weight of polyester rope but has chain at the bottom to allow seabed contact. In some cases, the mooring can maintain seabed contact and allow drag-embedment anchors.		Design variables: • Chain size • Chain length • Rope size • Rope length • (Anchor spacing)

The specific shared mooring line configurations considered in the project are given in Table 4.

Table 4: Shared mooring line configuration options

Catenary chain This catenary all-chain line is the simplest shared mooring arrangement, where its stiffness is determined by the chain weight and the shape of the catenary.		Design variables: • Chain size • Chain length
Chain with float This arrangement uses a float in the middle of a chain line to enable a more compliant shared mooring while reducing the weight on the turbines.		Design variables: • Chain size • Chain length • Float buoyancy
Chain with weights This arrangement adds two clump weights to the chain line to increase the mooring stiffness without increasing the chain size or increasing the mooring's depth.		Design variables: • End chain size • End chain length • Mid chain size • Mid chain length
Semi-taut chain-rope This hybrid arrangement uses a length of polyester in the middle to reduce the mooring weight for a given distance. It also reduces the mooring stiffness.		Design variables: • Chain size • Chain length • Rope size • Rope length
Rope with weight This semi-taut shared mooring arrangement uses a single clump weight to tune the stiffness properties, lower the depth, and provide compliance for a polyester mooring line.		Design variables: • Rope size • Rope length • Weight
Rope with 2 weights This semi-taut arrangement uses two clump weights to provide a more cost-effective tuning of the polyester line's compliance while keeping most of the shared line at a near-constant depth.		Design variables: • End rope size • End rope length • Mid rope size • Mid rope length • Weight

2.2.2 Modeling of Mooring Loads and Stationkeeping Response

Mooring positions and loads were measured using MoorPy, which computes the quasi-static response of the full moored floating system including couplings between different floating platforms and the nonlinear geometric response of individual mooring segments. MoorPy includes representation of rigid bodies with hydrostatic properties so that the floating wind turbines can be modeled in the coupled quasi-static solution. Mean loads were applied to the platform objects in MoorPy to represent the combined wind thrust force and wave-induced mean drift force.

Because this stage of the design process caters to steady or quasi-static system performance, the peak turbine thrust force of 1.5 MN was increased by 33% to conservatively represent the total short-term surge force that any one turbine may experience, for a total load of 2 MN. In the design process, mooring system stationkeeping targets were built around supporting the 1.5 MN mean thrust force, while the additional forces are added to provide safety margin for inclusion of dynamic effects on the mooring lines. These assumptions were removed during the next stage of the project, which involved a full dynamic analysis.

2.2.3 Mooring Design Constraints

Design constraints were used to ensure that an optimized design met certain physical criteria. Each mooring configuration requires a given set of constraints, plus another set of constraints specific to the physical system that it is in. At the highest level, the overall mooring system was sized to achieve a maximum mean offset (or watch circle radius) of 60 m, which is 10% of the water depth.

All mooring lines were sized to meet tension, stiffness, and strength constraints. The horizontal tension of the mooring must match a specific target value that is determined by the linearized array-level mooring optimization. The effective horizontal stiffness of the mooring must meet or exceed a target stiffness, that has also been set by the linearized array-level optimization, to ensure each platform’s offsets are within the specified limit.

In accordance with API RP-2SK [7], a safety factor of 2 was used for sizing the mooring lines based on the largest tension predicted using quasi-static analysis. In other words, quasi-static tensions cannot exceed 50% of the minimum breaking load (MBL) of each line segment in a mooring line.

Anchored mooring lines were subject to up to two anchored-mooring-specific constraints depending on the configuration: a minimum lay length constraint, and a zero-rope contact constraint. The minimum lay length constraint was applied to anchored mooring configurations with a drag-embedment anchor because a drag-embedment anchor cannot support vertical loads. It requires that a specified amount of mooring line length be left on the seabed so that a mooring line does not produce any vertical loads on the anchor. This is considered in the undisplaced and extreme conditions of the mooring line. In other words, when the platform is at its farthest position away from the anchor, there will still be a minimum line length left on the seabed.

The zero-rope contact constraint was applied to anchored mooring line configurations that include a section of rope in the mooring line. The configuration could either have a drag-embedment or a suction pile anchor. For example, the taut synthetic rope configuration has only synthetic rope and a suction pile anchor, while the semi-taut chain-rope configuration has rope connected to a chain section on or near the seabed connected to a drag-embedment anchor. This constraint was applied to always keep the rope at a minimum height above the seabed to avoid abrasion from the seabed. Again, this was considered in the undisplaced and extreme conditions of the mooring line. In contrast to the lay length constraint, when the platform is at its closest position to the anchor, the mooring line was designed so that the rope section of the mooring will always be at least the minimum height above the seabed.

Similar to the safety factor applied to the tension of the mooring line, a safety factor was applied to the load capacity of the anchors. The anchor capacity for any given anchored mooring line is calculated based on the maximum force vector seen at the mooring's anchor end during quasi-static analysis. This force vector was increased by 20% to compensate for the quasi-static modeling approach and then scaled by the safety factors listed in API RP-2SK.

Shared mooring lines include two shared-mooring-specific constraints based on the depth of the lowest point of the mooring: a minimum clearance from the waterline and a maximum allowable depth. The minimum clearance, or minimum sag, was applied to shared mooring configurations to allow depth clearances from the waterline for shipping and navigation. Rope mooring lines can be neutrally buoyant so this constraint would ensure that the shared mooring ropes stay a certain depth below the waterline.

The second shared mooring line constraint is similar to the minimum clearance, but in the opposite direction. A maximum allowable depth constraint was applied to all shared mooring configurations to prevent the lowest point of the mooring line from coming too close to the seabed. In practice with, this constraint was never active when optimizing the mooring designs for cost.

Table 5 shows a list of the mooring line configurations considered in this project and which constraints were applied to each.

Table 5: Constraints considered for each mooring line configuration

	Configuration	*Fx*	*Kx*	*FoS*	*Lay*	*Rope*	*Min Sag*	*Max Sag*
Anchored	Catenary chain	X	X	X	X			
	Taut rope	X	X	X		X		
	Semi-taut chain-rope	X	X	X	X	X		
Shared	Catenary chain	X	X	X			X	X
	Chain with float	X	X	X			X	X
	Chain with weights	X	X	X			X	X
	Semi-taut chain-rope	X	X	X			X	X
	Rope with weight	X	X	X			X	X
	Rope with 2 weights	X	X	X			X	X

Legend:

- Fx: horizontal tension constraint
- Kx: horizontal stiffness constraint
- FoS: tension safety factor constraint
- Lay: minimum line length constraint
- Rope: minimum height above the seabed constraint
- Min Sag: minimum depth below surface constraint
- Max Sag: maximum depth of shared mooring constraint

2.3 Iterative Shared-Mooring Optimization

To create an optimized shared mooring array with internally consistent assumptions, a separate design algorithm was developed to bring together the linear array optimization and the nonlinear mooring sizing processes. It begins with a linear array optimization based on initial mooring property assumptions. Then, the optimized linear mooring properties are passed as target values to the nonlinear mooring optimizer. The nonlinear optimizer then optimizes each mooring, considering the selected mooring arrangements and all applicable constraints, to achieve the lowest cost mooring design that meets the criteria.

Next, the properties of each optimized mooring are linearized and used to update the assumptions in the linear mooring system optimizer, which can then be rerun to initiate a new iteration. Repeating in this way, the two optimization processes are iterated between until the mooring properties and assumptions converge and a true least-cost mooring system design is achieved. The process is illustrated in Figure 11.

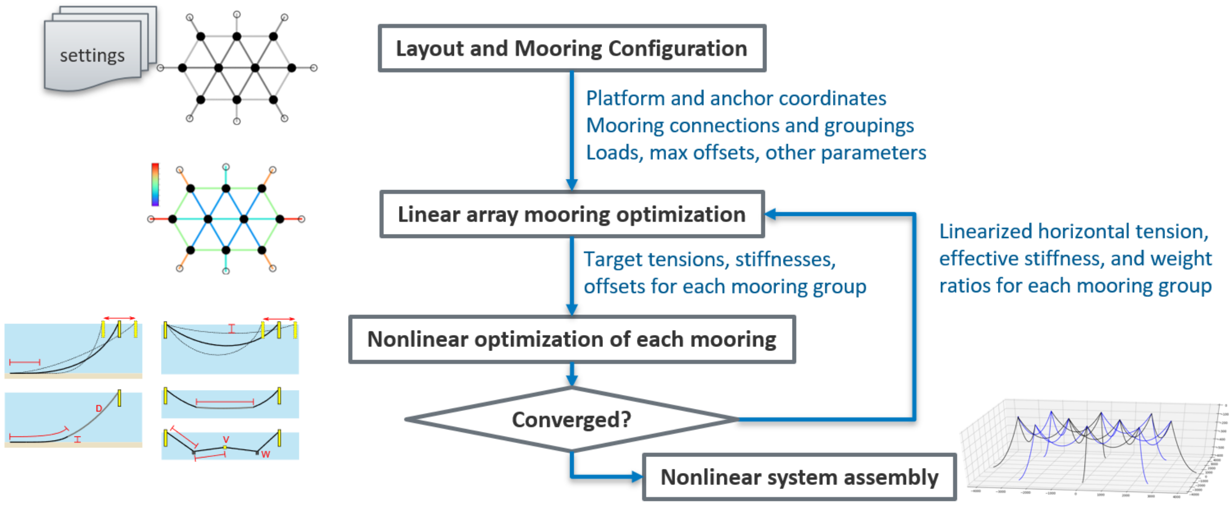


Figure 11: Iterative system-level shared mooring optimization process

Applying this optimization process to various array layouts and using various mooring arrangements showed that the computation time needed to optimize more complicated mooring arrangements can result in the overall process to become quite slow (hours rather than minutes). Furthermore, different arrangements pose different requirements on the linear array optimization stage, so changing arrangements mid-optimization disrupts the iteration process. Lastly, the linearizing assumptions in the linear system sub-optimization requires a multiplier to leave room for nonlinear effects that can increase offsets, and this requires manual tuning at this stage. With these practical considerations in mind, the following general design process was used when optimizing the mooring system for a given shared-mooring array layout:

1. Define the layout and general design parameters.
2. Run the system-level mooring optimization process (Figure 11) for generic mooring arrangements (e.g., single-component chain catenary moorings).
3. Verify the offsets using nonlinear coupled analysis and adjust the nonlinear multiplier as needed until the linear offset predictions align with the nonlinear ones.
4. Extract mooring design target values from the optimized system.
5. Run independent nonlinear mooring optimizations with different arrangements to determine the most cost-effective arrangement for each mooring group in the system.
6. Re-run the full system-level mooring optimization using the selected mooring arrangements.

This approach balances computation time efficiency, thoroughness in considering multiple options, and rigor in evaluating the final design for accuracy and minimal cost.

2.3.1 Final Conceptual Design

With the layout selected, all the mooring line configuration options in Table 3 and Table 4 were evaluated using the sizing algorithm set to the layout's requirements. The configurations for the shared and anchored mooring lines were selected based on the resulting size and performance estimates, along with some manual adjustments to suit practical considerations of the layout.

The selected anchor line configuration was taut polyester line with suction pile anchors. This configuration provided the lowest cost and lowest mooring system weight compared to semi-taut and catenary options. For the shared mooring lines, the configuration with polyester rope and two clump weights was selected. It was found to have the lowest cost while satisfying the constraints. Additional advantages of this arrangement are that its clump weights allow easy adjustment of its tension and stiffness characteristics, and the majority of the shared line is at a near-uniform water depth, making it simpler for navigation.

With the mooring line configurations selected, the design assumptions were updated and the full optimization process was rerun to yield the final conceptual design. A three-dimensional view of the conceptual shared-mooring array design is shown in Figure 12, and Figure 13 shows top and side views of the mooring system in its equilibrium position. As noted earlier, the layout features a staggered row of ten turbines that are moored together one after the other, with successive shared moorings at right angles to each other. This arrangement creates a coupled mooring system by repeating a pattern of a shared-mooring turbine pair in alternating orientations. The alternation has the important effect of minimizing the coupling effects from one shared line to the next—an effect that caused stationkeeping challenges in other layouts.

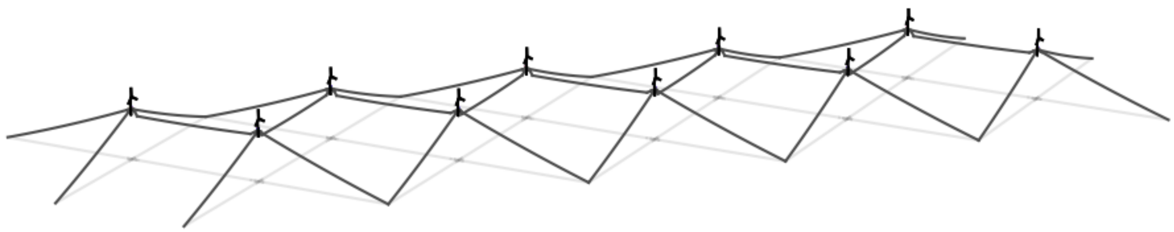
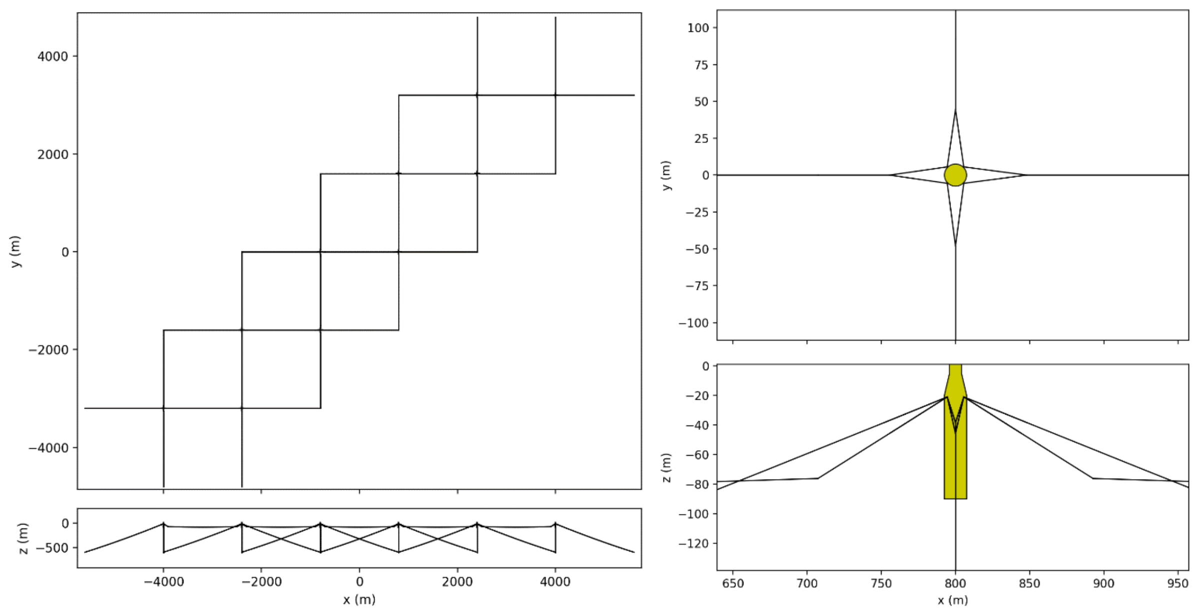


Figure 12: Perspective view of the conceptual shared-mooring array design



(a) Full view (b) Zoomed in view

Figure 13: Top and side views of the conceptual shared-mooring array design

As discussed in Section 1.3.2, all mooring lines use a bridle configuration when attaching to the turbine substructure. Since the proposed design has four evenly spread lines per turbine, the attachment points are spread by 90° as shown in Figure 13(a). Each bridle line segment is sized at 45 m long, to give a moderate spread angle, and is given identical properties to the rest of the mooring line for simplicity at this stage. Figure 13(b) shows the bridle arrangement of the mooring attachments for the conceptual design. Figure 14 shows a closer view of the shared mooring lines in the array. The full details of the mooring system are given in Table 6.

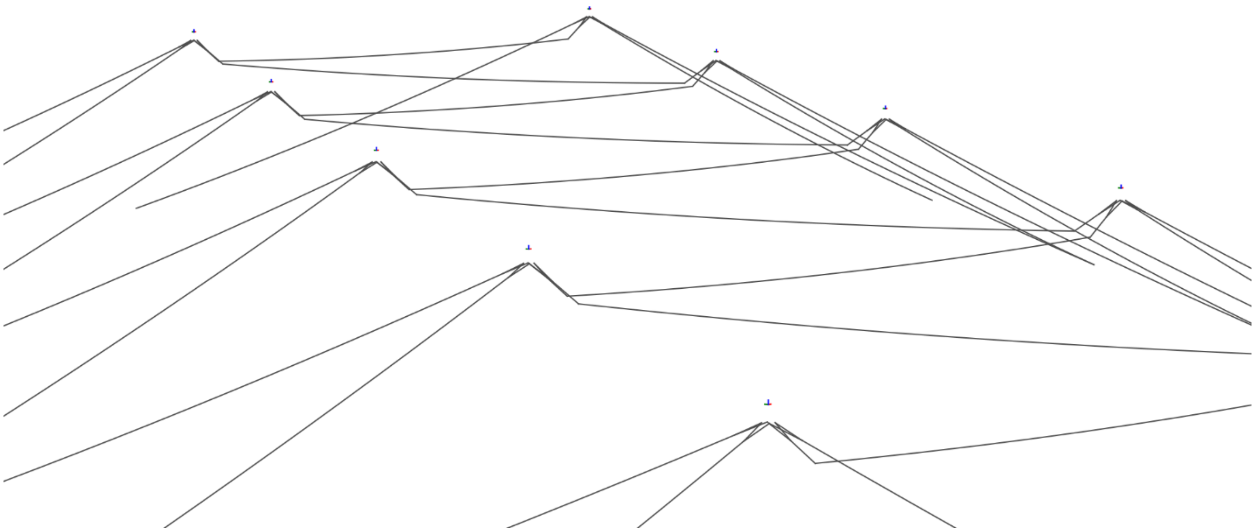


Figure 14: View of the shared mooring system including bridle arrangement

Table 6: Properties of the baseline and shared mooring system designs

	Conceptual Shared-Mooring Design		*Baseline Design*
Mooring arrangement	Shared-Rope with 2 weights	Taut-Rope with suction pile	Taut-Rope with suction pile
Mooring material	polyester	polyester	polyester
Horizontal spacing (m)	1600	1600	1600
Number of lines in array	9	22	30
Diameter (mm)	200	213	175
Minimum breaking load (MN)	6.80	7.73	5.22
Clump weight mass (t)	100		
Segment lengths (m)	1363.3 (mid span) 54.6 (above clump) 45.4 (bridle segment)	1594.7 (from anchor) 45.4 (bridle segment)	1599.1 (from anchor) 45.4 (bridle segment)
Anchor type	(Shared Line)	Suction Pile	Suction Pile
Number of anchors in array		22	30
Anchor holding capacity (t)		763	516

2.4 Cost Modeling

With the goal of optimizing shared-mooring floating wind turbine arrays, the mooring system components need to be sized to minimize the overall cost of the system. This section presents the mooring component property- and cost-modeling techniques that were used to estimate the costs of the baseline and conceptual designs.

2.4.1 Background

The design of a shared mooring system requires knowledge and data on the properties and characteristics of the mooring system components. In this project, the mooring system components considered were mooring lines, anchors, and clump weights. Mooring line properties include line nominal diameter, volumetric diameter, mass density, weight, axial stiffness, maximum breaking load, and cost. Anchor properties include weight, soil condition, maximum load vector, and cost. The cost of mooring lines and anchors can be broken down into manufacturing costs, installation costs, maintenance costs, and decommissioning costs. The maintenance demands between a shared mooring system and the baseline mooring system are expected to be similar and as such, maintenance costs will not significantly affect the design selection process. Mooring system maintenance costs are therefore not included at this stage, as they are difficult to model (e.g., [16]). However, full farm operation and maintenance costs were included later during the LCOE analysis in Section 5.3.

The most reliable mooring system component property data comes from mooring component vendors and manufacturers' catalogs. This involves extensive research and analysis to find various manufacturer catalogs, pull the data for each property of each type of mooring component, and document the data. One of the most popular commercial mooring analysis tools, OrcaFlex, has derived their own mooring line property relationships based on manufacturer data for various mooring line types [17]**.** They include line properties such as volumetric diameter, mass density, weight, axial stiffness, and maximum breaking load, but no cost. NREL has several internal collections of mooring property data. FloatingSE, a floating support structure design and optimization tool in NREL's WISDEM package, has its own set of mooring line property relationships that are similar to OrcaFlex's relationships and includes cost from an external mooring analysis study [18]**.** Another NREL-internal source contains mooring line and anchor property data with similar trends of data to FloatingSE for some mooring line types, but not all. NREL's balance-of-system cost model for offshore wind, ORBIT, uses cost estimates for mooring lines and anchors but the assumptions are only for one mooring line type and do not include all significant properties [19]**.**

There are also a handful of public mooring system optimization studies that use their own mooring property data but are usually tailored for that specific study and do not include all relevant properties.

Mooring system component costs, as opposed to properties, are typically more difficult to find. Some of the sources listed above, such as FloatingSE and ORBIT, as well as various public studies [20]–[22], estimate or assume mooring line material costs but provide little justification. Other design costs, such as installation and decommissioning costs can be found in a handful of other public sources [23], [24]**.** Given uncertainties in these sources, estimates of up-to-date mooring component costs were instead elicited from mooring experts in industry.

To provide a consistent and organized set of assumptions for mooring system component property and cost information, a library of these data—synthesized from the various data sources mentioned—was developed and included in the MoorPy public repository. This working library of mooring system component data was used extensively in this project and will be continuously developed for use in future moorings research projects as well.

2.4.2 Mooring Component Property and Cost Assumptions

Selecting a conceptual shared mooring system design based on an optimization to minimize the cost of the mooring system requires accurate mooring component property data, which were gathered and developed throughout the project. There are many mooring line types, such as chain and synthetic rope, as well as mooring line properties, such as mass and axial stiffness, to consider in this process, which increases the complexity of the optimization problem. For a given line type, these properties can be expressed as a function of line diameter.

2.4.2.1 Mooring Lines

The project considered two types of mooring line material: chain and polyester rope. To visualize the differences in line properties, each line type's properties are expressed as a function of line diameter and are plotted against the other line type's properties in Figure 15.

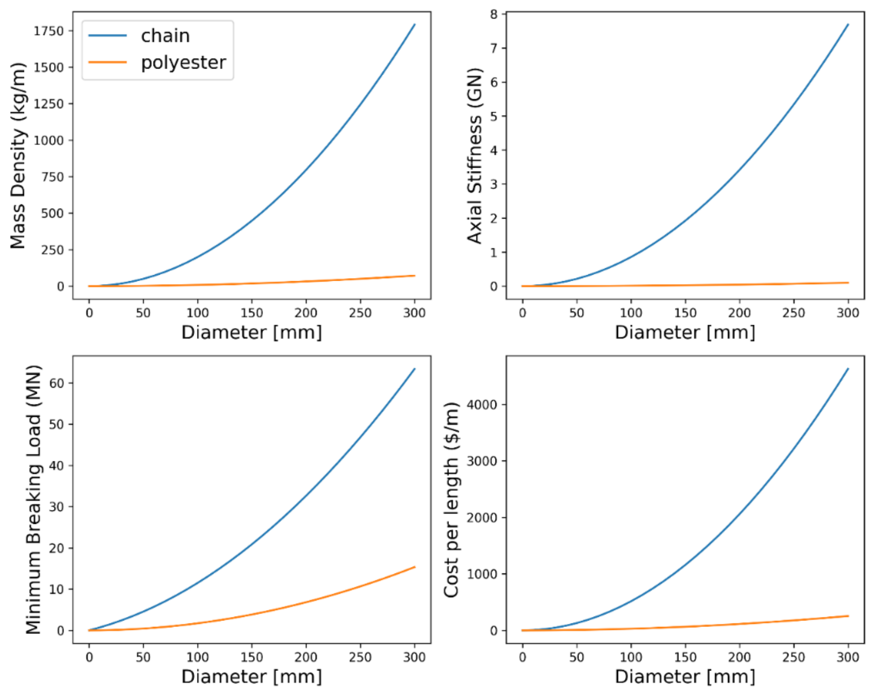


Figure 15: Mooring line properties assumed for chain and polyester rope

The chain is assumed to be an R4 studless chain and the synthetic rope is assumed to be polyester. The prescribed diameter is the nominal diameter, the mass density is the mass per unit length in air, and the weight is the weight in water, which includes the effect of buoyancy. The variable EA denotes the product of the material's Young's modulus and the line's cross-sectional area. The MBL is the minimum breaking load, which is the quantity used to represent line strength when determining safety factors.

These plots show the differences in mass, stiffness, strength, and cost of the two mooring line types considered in this project. The mechanical values are similar to those used by OrcaFlex [17] but modified to avoid inconsistencies in the upper and lower diameter extremes, which can otherwise interfere with optimization processes. Each line property is a quadratic function of line diameter. Chain is heavier, stiffer, stronger, and more expensive than polyester rope.

The most notable mooring line property is its cost since the conceptual design is based on the minimized cost of the mooring system. Cost models can vary by industry factors such as the vendor, the size of the order, and outside market conditions. Gross simplifications of mooring line costs were derived from industry advisors' estimates. These simplifications are based on the price of material and have been adjusted to estimate the shipping, handling, storing, and other installation costs of the lines. The cost of chain is a function of the chain's mass and is estimated at $2.585/kg for grade 4 chain. The cost per meter of polyester rope is a function of the rope's minimum breaking load and is estimated at $0.162/Mt/m, or $1.65e-5/MN/m. These mooring line cost model estimates have a large influence in the overall cost of a mooring system. Even though they are simplifications, they can still provide cost information to support decision-making on conceptual shared-mooring designs.

2.4.2.2 Anchors

The project considered two different anchor types: drag-embedment anchors (DEAs) and suction piles. DEAs are the cheaper option between the two, but do not have the capacity for vertical loads. Suction piles are more expensive but can handle loads from all directions. The most significant anchor properties are its weight, soil compatibility, load vector, and cost, with cost being the most relevant for this project. Anchor cost estimates were derived from industry partners' data and used to evaluate different shared mooring system designs.

The manufacturing cost of each type of anchor considered is plotted against a range of loadings to show the cost variation in Figure 16.

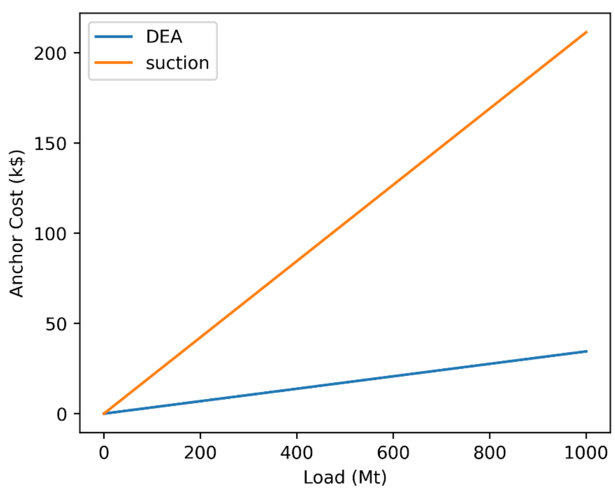


Figure 16: Anchor cost assumptions

As stated before, DEAs are much cheaper than suction piles. However, they require mooring lines to rest on the seabed so that no vertical force is applied to the anchor. This can raise the cost of the attached mooring line if it requires a longer line. On the other hand, suction piles are more expensive, but can enable a much shorter line.

2.4.2.3 Installation, Decommissioning, and Other Costs

The installation and decommissioning costs of the moorings are an important factor to include in the overall cost of a shared moorings system since they are on the same order of magnitude as the manufacturing costs. For these initial conceptual design selection purposes, estimates for the installation cost per anchor and the decommissioning cost per anchor were included in the overall system cost [24].

Table 7: Installation and decommissioning costs per mooring line

Cost per Mooring	*Drag-embedment*	*Suction Pile*	*Shared Mooring*
Installation ($)	192,987	211,610	0
Decommissioning ($)	270,181	148,128	0

The installation and decommissioning costs of each mooring line are assumed to be driven by the anchor operations, while costs for installing a shared mooring line are neglected due to a lack of data. Depending on the number of anchors in a shared moorings design, these non-manufacturing costs can have a significant effect on the overall system cost and can influence the design selection process.

Mooring maintenance costs typically include preventative and corrective maintenance, which can further be divided into transport, labor, and mooring component costs [25]. These factors are not expected to vary significantly between shared and anchored mooring lines and are not expected to put either the shared-mooring or baseline design at a relative advantage. As discussed in 2.4.1, operations and maintenance costs were not considered in the scope of the project.

2.4.3 Initial Stationkeeping System Cost Results

The cost assumptions described above informed the selection and optimization of the conceptual shared mooring system design. Mooring system component properties and costs are the driving forces in the optimization and selection. Reliable mechanical properties have been consolidated from various sources and cost estimates have been derived from industry partners, as well as other studies. The cost breakdowns of the baseline and shared-mooring designs are tabulated in Table 8.

Table 8. Initial stationkeeping cost comparison for 10-turbine array designs

	Conceptual Shared-Mooring Design		*Baseline Design*
Mooring Arrangement	Shared-Rope with 2 weights	Taut-Rope with suction pile	Taut-Rope with suction pile
Mooring Line Types	polyester	polyester	polyester
Number of Lines	9	22	30
Diameter (mm)	200	213	175
Clump weight (t)	100		
Lengths [m]	1363.3 (mid span) 100 (above clump)	1640	1644.5
Cost per Line (k$)	175	207	140
Anchor Type	(Shared Line)	Suction Pile	Suction Pile
Number of Anchors	0	22	30
Cost per Anchor (k$)	0	824	557
Mooring Installation Cost (k$/mooring)	0	212	212
Mooring Decommissioning Cost (k$/mooring)	0	148	148
Total Cost of Lines (k$)	1,575	4,554	4,200
Total Cost of Anchors (k$)	0	18,128	16,710
Total Installation Cost (k$)	0	4,664	6,360
Total Decommissioning Cost (k$)	0	3,256	4,440
Total Stationkeeping System Cost (k$)	32,180		31,710

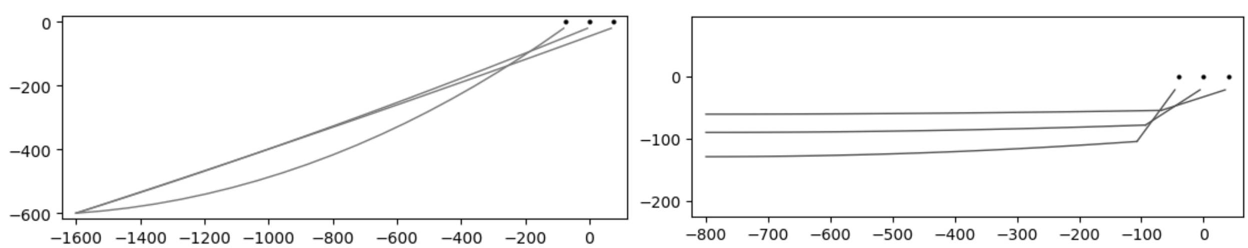
The specific shared mooring design was selected based on the relative number of turbines in the array, as well as the overall cost relative to the other array layouts tested. The shared mooring line configuration and the anchored mooring line configuration that are part of the shared mooring design were the cheapest line arrangements that met all constraints.

Summing the cost of each mooring line, anchor, and the installation and decommissioning costs, the overall cost of the shared mooring design was 1.4% more expensive than the baseline design at this stage of the design process. These cost estimates include many assumptions and are only from a quasi-static analysis. The designs were later refined based on dynamic loads analyses.

2.5 Design Performance and Discussion

Nonlinear analysis of the shared mooring array shows that the mean offsets of each turbine across all loading directions are within 5 m of the target watch circle radius of 60 m. The conceptual mooring system design relies on polyester rope, resulting in a relatively taut mooring arrangements. The resulting force-displacement behavior is well suited to the stiffness requirements of the array, given the large water depths and spacings involved in conjunction with the elasticity of polyester lines.

Figure 17 shows the profiles of the anchor mooring arrangement and the shared mooring arrangement. The anchor arrangement is visibly taut and only loses tension near the extreme negative offset. Even in this case, some angle off the seabed is maintained, meaning no significant seabed contact is predicted by this level of analysis. In practice, some length of chain could be required for withstanding seabed contact around where the line attaches to the anchor, assuming the padeye is below the seabed. This small chain length was neglected in the design process because it would have minimal impact on the mooring behavior.



(a) Anchor line profile

(b) Shared line half-profile

Figure 17: Mooring profiles show undisplaced and extreme-displaced states

The shared mooring lines rely heavily on clump weights for achieving their target stiffness value while maintaining adequate depth below the surface (for navigation) and supporting a range of relative motions. A 100 m length between the clump weight and the platform eliminates any collision hazard in the case of the shared line failing.

All design constraints specified for the selected mooring arrangements are met according to quasi-static analysis as discussed in Section 2.2. This means that all mooring line segments have a safety factor of at least 2.0 in the highest-load state simulated, and the constraints on the anchored and shared line profiles are satisfied through the range of expected motions.

Figure 18 gives an illustration of the platform reference point and mooring line ranges of motion over 180° of the peak 2 MN loading on each turbine. This shows moderate and regular motion envelopes for the mooring lines, with the largest variation being when a downwind anchor line becomes less taut. These results appear reasonable for the current level analysis, but they will be revisited in Task 3 using coupled dynamics analysis.

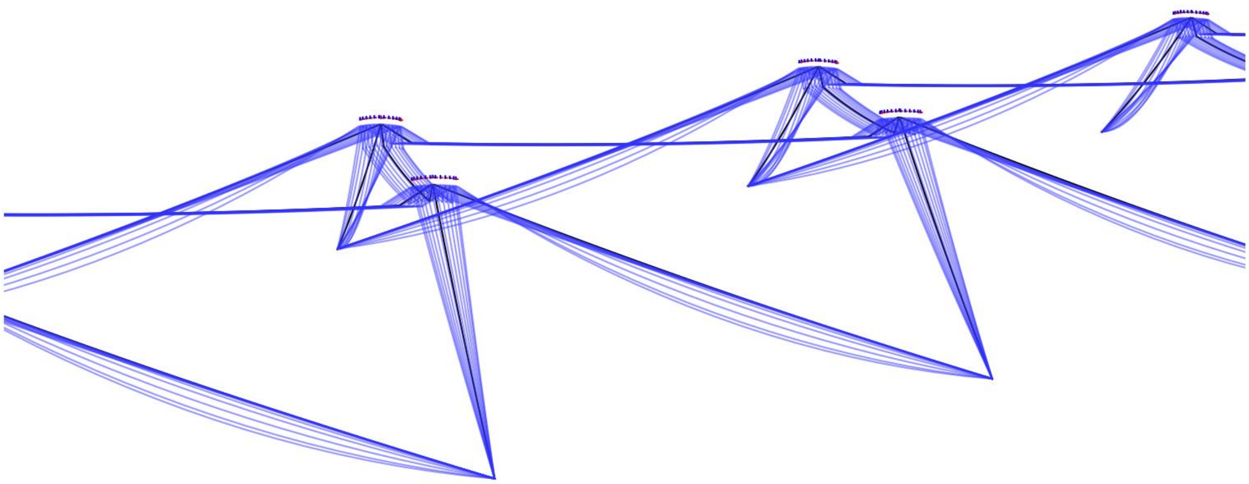
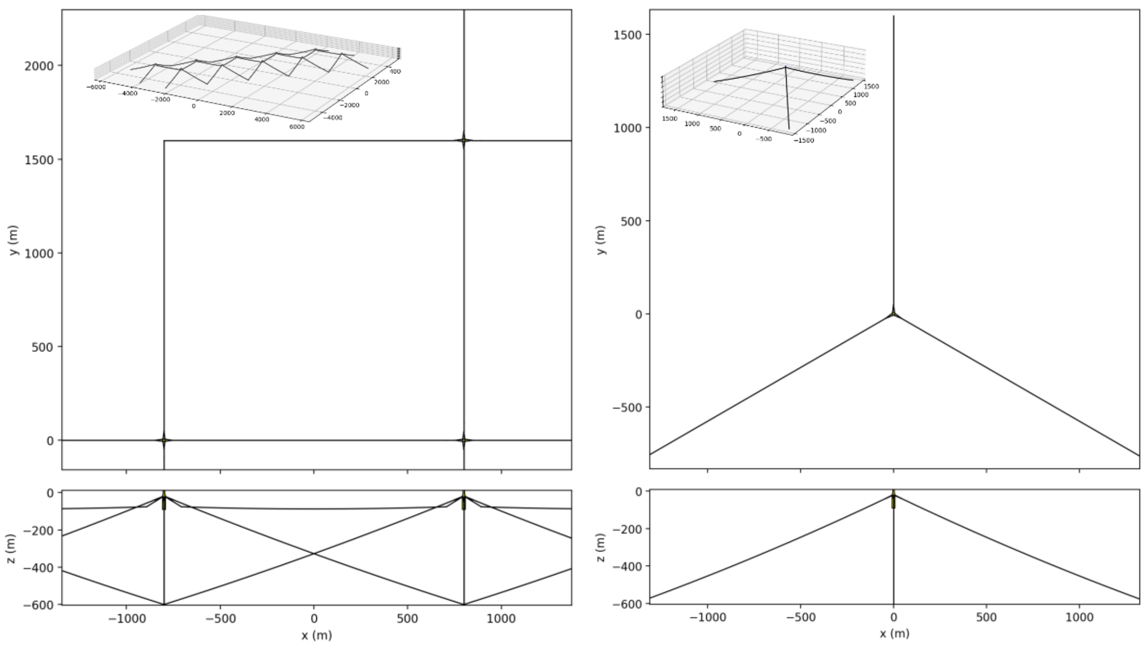


Figure 18: Illustration of mooring displacement ranges for maximum steady loads over 180°

For spar designs, the yaw stiffness and natural period is often a concern. In the conceptual design, the yaw natural frequency of each turbine unit is 23.6 seconds, which is significantly smaller than the expected roll and pitch natural frequencies. This comparison is related to avoiding a motion instability between the roll and yaw degrees of freedom on a floating wind platform. As detailed in [26], the stability check is a function of the thrust force, the hub height, the total inertia matrix of the platform, the mooring stiffness term in yaw, and the hydrostatic stiffness in roll. At relatively large thrust forces, a floating wind platform can achieve an unstable mode. For the properties of the conceptual shared mooring system design, the turbine thrust force is significantly less than the magnitude that would cause instability.

2.5.1 Comparison of Shared-Mooring and Baseline Designs

The individual baseline mooring system was re-optimized using the same assumptions as the conceptual design to provide a fair cost comparison between the designs. Its properties are given alongside those of the conceptual design in Table 6. Both designs using taut moorings with suction pile anchors at 1600 m spacing. A visual comparison of the conceptual and baseline designs is provided in Figure 19. As presented in Table 8, the estimated stationkeeping system cost for the conceptual design was $32.2M and for the baseline design was $31.7M (assuming an equivalent array of 10 turbines).



(a) Shared-mooring design (b) Baseline design

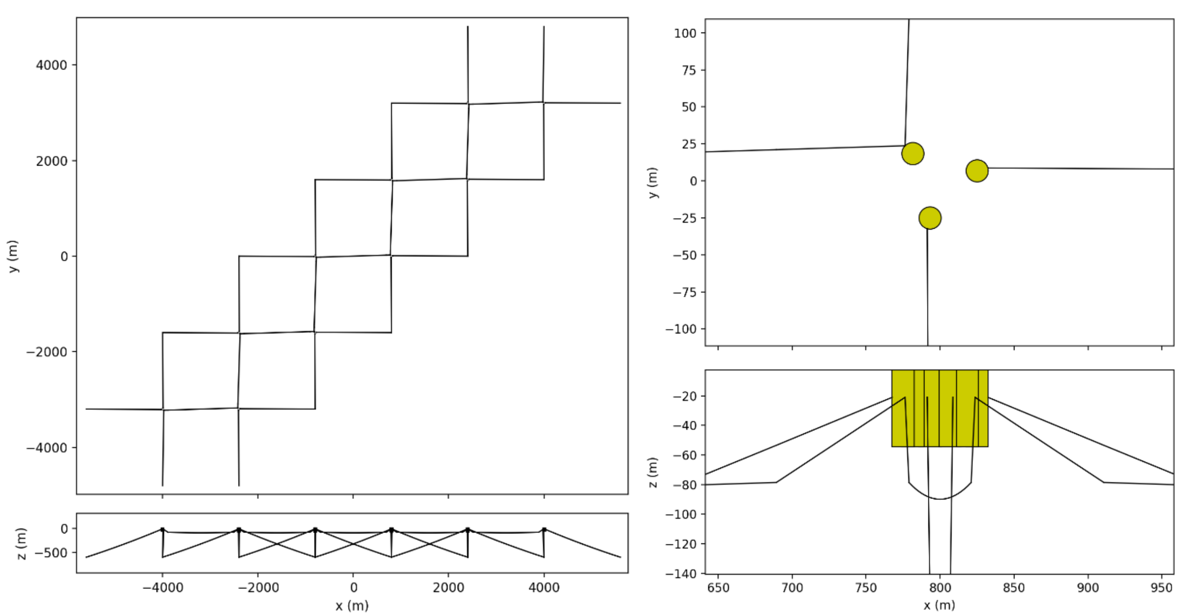
Figure 19: Top and side view comparisons of shared-mooring and baseline designs

The suction pile anchors were sized to meet the safety factors from API RP-2SK, which mandates a factor of 1.6 in the horizontal direction and 2.0 in the vertical direction. As mentioned in Section 2.2.3, loads were increased by 20% above the predicted maximum quasi-static loads to account for dynamic effects. The anchor holding capacity in the shared-mooring conceptual design is 763 t, compared to an anchor capacity of 516 t required for the individual baseline mooring design. Considering the shared mooring design has 27% fewer anchors, the total anchor mass and cost required of the shared design is 8.5% larger than the baseline design.

An opportunity to significantly lower the anchoring costs of the shared-mooring design exists in the form of sharing anchors. The conceptual design's anchor positions are specified as coincident to enable this possibility. Given the 30% net load reduction from adding two perpendicular loads, this design adjustment could reduce the shared mooring configuration's total anchor mass and cost to 20% below that of the baseline configuration. This option was explored further in later stages of the project. For the non-shared-anchor approach, which the current conceptual design analysis assumes, the doubled-up anchor positions can be considered as slightly separated apart by tens of meters (a negligible distance relative to the 1600 m anchor spacing).

2.5.2 Adaptation to a Semisubmersible Platform

To check compatibility of the conceptual design with semisubmersible platforms, the final mooring design optimizations were repeated using fairlead positions corresponding to the SWE Triple Spar Platform [27]. This is a semisubmersible design that has been well studied in Europe and also features the DTU 10 MW turbine, providing an ideal basis for comparison. The adjusted array layout is shown in Figure 20(a). The most notable difference for the mooring system is that the fairlead radius from the centerline increases to 33.5 m, and at this radius, no bridle configuration is required. Because this platform has 3 columns and the mooring layout uses 4 anchors per turbine, each turbine's 4 mooring attachments needed to be distributed to its 3 columns. To solve this, two shared lines were attached to the same column, as visible in Figure 20(b). Figure 21 provides a three-dimensional view of the shared line attachments (comparable to Figure 14). Without adjusting the turbine or anchor positions, the attachment changes resulted in a slight change to the mooring lines' headings relative to those in the spar layout. The array is still balanced and has nearly identical restoring properties.



(a) Full view

(b) Zoomed in view

Figure 20: Top and side views of conceptual shared mooring system design with semisubmersible

Figure 20(b) shows zoomed-in top and profile views. The profile view contains two platforms that are inline with each other, with the same *x* coordinate but different *y* coordinates. These two platforms have different orientations due to the direction of their shared mooring line attachments. The profile view shows the overlap between those two platforms and their respective shared and anchored mooring lines.

Despite the absence of bridle connections and the change in fairlead positions, the semisubmersible adaptation of the conceptual shared mooring system design has negligible changes to the overall results. With the change in fairlead radius, the length of the shared mooring line decreased from 1,363 meters to 1,330 meters and the anchored line length decreased by 24 meters. Their diameters and minimum breaking loads change slightly, but not enough to change the behavior of the overall design. The distinct properties of the spar and semisubmersible shared mooring system designs are compared in Table 9.

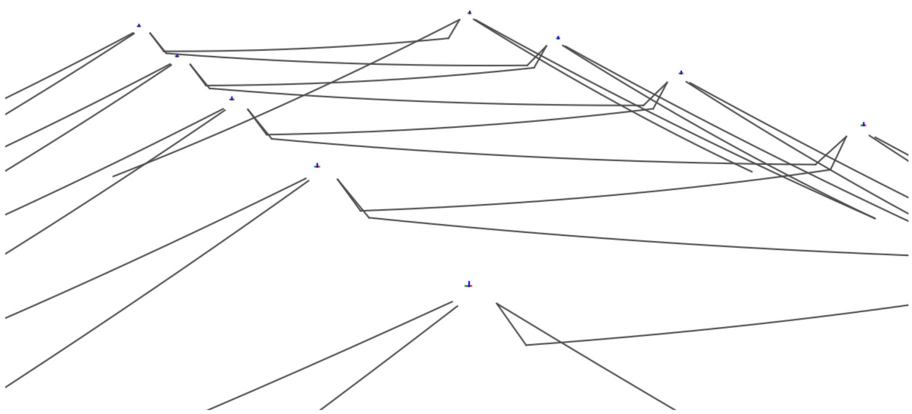


Figure 21: View of the shared mooring system for the semisubmersible variant

Table 9: Comparison of shared-mooring design with spars and semisubmersibles

	Mooring Design with Spar	*Mooring Design with Semi*
Fairlead attachment	Bridle on all lines	Common shared line location
Fairlead radius (m)	7.87	33.5
Shared line length (m)	1363.3 (mid span) 54.6 (above clump) 45.4 (bridle segment)	1330.3 (mid span) 100.0 (above clump)
Shared line diameter (mm)	200	197
Shared line MBL (MN)	6.80	6.64
Anchor line length (m)	1594.7 (from anchor) 45.4 (bridle segment)	1616.8 (from anchor)
Anchor line diameter (mm)	213	212
Anchor line MBL (MN)	7.73	7.65
Anchor holding capacity (t)	763	756
Total stationkeeping cost	$32,180,000	$31,850,000

Relative to the costs of the original spar-based conceptual shared mooring design, the semisubmersible variant sees the cost of each shared mooring line increase from $175,000 to $176,000, and the cost of each anchored mooring line increase from $207,000 to $209,000. Because the semisubmersible design has a slightly smaller anchor capacity, it sees the total stationkeeping system cost reduce from $32,180,000 to $31,850,000—a change of just over 1%. This high degree of similarity confirms that the conceptual design is equally suitable for spar and semisubmersible platform designs according to the current analysis approach.

2.6 Conclusion

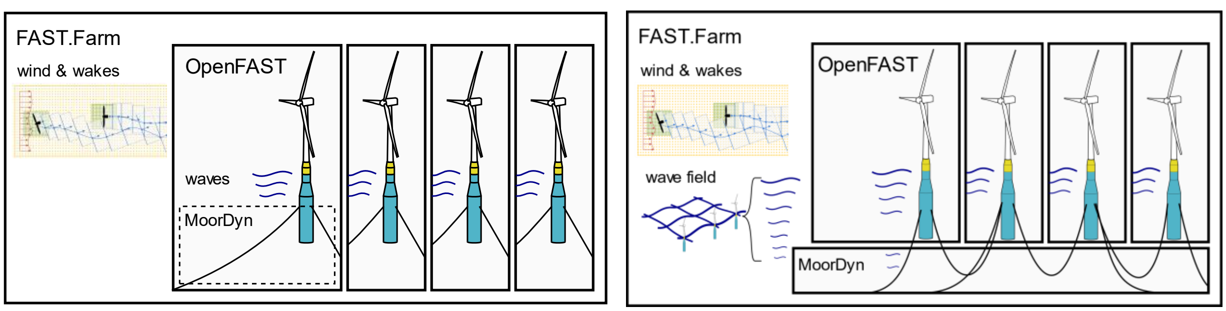
A shared mooring system design framework for floating wind arrays was completed and successfully applied to create a shared-mooring conceptual design. This process demonstrated the newly created design process and revealed how it can best be used. It was most practical to combine the automatic optimization process with manual decision making at several points in the process. Altogether, the shared mooring design optimization process proved to be successful and an essential tool to navigate the complexities of shared mooring system design.

Over 40 array layouts were systematically evaluated during the conceptual design process to arrive at the best design. The selected conceptual shared-mooring system design couples the turbines together sequentially with alternating perpendicular shared lines to minimize propagation of coupling effects through the array. The conceptual design meets all constraints and performance goals, as analyzed with the current quasi-static models. Its cost is comparable to the conventional baseline design using current estimates. This represents a preliminary benchmark, before dynamic analyses were done and both the conceptual and baseline designs were refined based on these more comprehensive performance results.

3 Mid-Fidelity Modeling Tool Development

This section describes the improvements made to the OpenFAST suite of tools, including FAST.Farm, HydroDyn, and MoorDyn to allow enable coupled dynamics simulations of shared-mooring floating wind farms. OpenFAST is NREL's flagship floating wind turbine simulation tool, which performs nonlinear time-domain coupled analysis of a floating wind turbine system including aerodynamics, structural response, hydrodynamics, mooring dynamics, and control [28]. Within OpenFAST, HydroDyn is a module that calculates the fluid-structure interaction with the ocean, and MoorDyn is a module that calculates the mooring system dynamics [29]. FAST.Farm is an extension of OpenFAST that allows the simulation of an array of floating wind turbines by coupling multiple OpenFAST simulations through a wake aerodynamics model [30].

Shared mooring systems are known to have unique system dynamic behaviors due to the mechanical coupling between floating platforms caused by the shared mooring lines [4], [31]. Until now, a capability for modeling this coupling within state-of-the-art floating wind simulation tools has not existed. NREL's OpenFAST suite of tools, including FAST.Farm for array simulation, also lacked the ability to simulate moorings between multiple turbines or to account for the propagation of waves throughout a floating array. FAST.Farm and its modules HydroDyn and MoorDyn were modified to provide these new capabilities, as depicted in Figure 22 and explained in the following subsections.



(a) Original configuration (b) Update with shared-mooring support

Figure 22. FAST.Farm module configuration update for this project

3.1 Wave Kinematics

The propagation of waves through a floating wind farm will result in differences in the timing of wave loads on each turbine. Because shared mooring lines connect adjacent turbines and create a coupled response, the timing or phasing of the loads on adjacent turbines is an important factor for the tensions of the shared mooring lines and the overall floating array's response. A previous study of these effects for shared-anchor floating wind farms found that there was little difference in the resulting anchor loads if the phases of the wave loads on the floating platforms were accurately modeled according to the wave propagation, or were simply randomized [32]. However, the coupled effects are more significant for shared mooring lines, so this project took the approach of accurately modeling the wave propagation.

3.1.1 Approach

Two general approaches are possible for capturing the wave load phasing due to wave propagation through the array (Figure 23): an approach that adjusts the wave field for each turbine individually, or an approach that models the wave field throughout the farm and then samples the relevant parts for each turbine. To meet the project needs efficiently, the first approach was implemented.

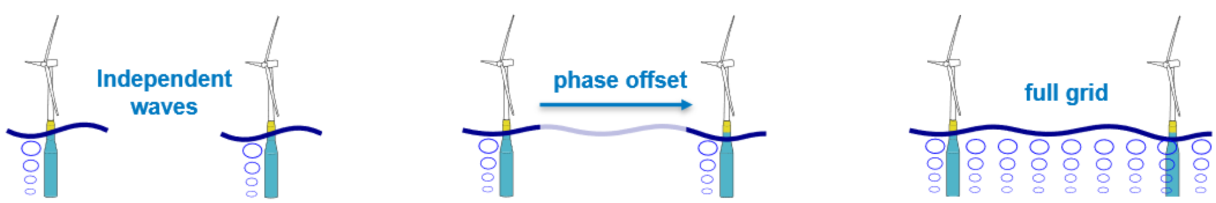


Figure 23. Options for realizing wave loads on floating platforms in an array

In this "phase offset" approach, the phases of the wave kinematics and loads are individually adjusted for each turbine based on its location within the array. This involved giving each floating wind turbine simulation new information about its location within the array, and then modifying its individual wave calculation routines to apply the phase difference based on its position. This approach resulted in minimal changes to the user experience, requiring just one additional input in the FAST.Farm input file to specify whether this phase shifting approach should be enabled or disabled. This capability provides for proper phasing of wave loads on each turbine as waves propagate across a floating wind array.

3.1.2 Implementation

The HydroDyn module in OpenFAST was modified to adjust the phasing of wave kinematics in the OpenFAST simulation based on the turbine's specified location within an array. FAST.Farm was then modified to pass the turbine location information to OpenFAST/HydroDyn so that this wave phase adjustment could be enabled at the array scale. The new capability integrates tightly with the existing FAST.Farm implementation, requiring only one additional user input, called "Mod_WaveField," in the FAST.Farm primary input file.

3.2 Shared Mooring Lines

Modeling the array-wide coupled dynamics created by shared mooring lines in a floating wind farm is the most important requirement for analyzing a shared-mooring floating wind farm's response. No publicly available methods for performing that coupled simulation existed at the beginning of the project. Tools such as OrcaFlex could be used to simulate interconnected floating bodies, but such tools could not model multiple wind turbines and their wake interactions. Previous work [4] used MoorDyn to simulate an entire array's shared mooring system and multiple FAST simulations to simulate each turbine. This provided the first published example of coupled simulations of multiple floating wind farms connected by shared mooring lines; however, it did not capture wake effects and used an old version of FAST.

3.2.1 Approach

The general approach to support shared mooring lines in FAST.Farm is to add institute an array-level MoorDyn model that can represent any/all mooring lines in the array and couple to any or all floating platforms in the array. This MoorDyn instance must be able to interact with the floating wind turbine FAST instances at the regular mooring model coupling time step (typically around 10 ms). It was set up in a way that can facilitate any shared mooring line configurations and any individual mooring line configurations previously supported. It also allows individual MoorDyn instances to be used for each turbine in the array, retaining the original capability for simulating non-shared arrangements.

3.2.2 Implementation

The MoorDyn module was previously only set up to be used with an OpenFAST simulation of an individual turbine. It featured one input mesh for receiving the kinematics of the mooring line attachment points as the floating platform moved, and it would produce one output mesh of the corresponding reaction forces at the mooring line attachment points.

The changes to let MoorDyn work for shared mooring systems involve two steps: (1) creating input and output meshes that support attachment to multiple floating platforms, and (2) converting between the local motions of those floating platforms (as tracked by OpenFAST) to their global motions within the array given the turbine spacings stored within FAST.Farm.

MoorDyn's single input and output meshes were changed so that they can be replicated for each platform that the mooring model is coupled with. The internal mooring connection mappings were similarly expanded so that line attachment points can be referenced to multiple turbines. MoorDyn now also accepts multiple platform initial condition vectors, along with a list of turbine x and y reference locations that define the positions of turbines in the array. These changes enable its use for coupled simulation of shared mooring lines and any other array-level simulation needs. They were implemented in such a way that MoorDyn's operation for individual turbines is minimally affected—only several changes to initialization input variables are required.

In terms of user inputs, specifying the shared mooring system in the array-level MoorDyn input file is very intuitive, involving only one change from regular MoorDyn input file use. When MoorDyn is run at the array level, an attachment point to a platform is indicated by the label "TurbineN," where "N" is the number of the turbine in the FAST.Farm. Similarly to fairleads in regular MoorDyn use, the X/Y/Z inputs specify the relative location of the fairlead on the turbine platform. Shared mooring lines are then specified just like other lines, by attaching them to the corresponding nodes that would constitute points on two different turbines. More information about the MoorDyn input file adjustments is available in the MoorDyn documentation[1].

3.3 FAST.Farm Integration

A range of changes were required in FAST.Farm to enable the wave-phasing and shared-mooring capabilities. Most of these are implementation details were very low level. However, the changes that enable array-level MoorDyn simulation involved a significant adjustment to how FAST.Farm operates.

Typically, FAST.Farm steps through time at a farm-level time step of around 2 seconds, and lets each individual OpenFAST turbine simulation advance independently over that period. However, shared mooring lines between the turbines would require analysis at a much higher time step—on the order of 1-

[1] https://moordyn.readthedocs.io/en/latest/usage.html#moordyn-with-fast-farm

20 milliseconds. To accommodate that, an intermediate time-stepping loop was implemented in FAST.Farm that calls each OpenFAST turbine simulation at whatever time step is required by the mooring model. This allows shared-mooring reaction forces to be coupled through the turbine models realistically.

Three new user inputs have been added to the FAST.Farm input file to control the new wave-phasing and shared-mooring features. They are listed in Figure 24 the same was as they appear in the input file.

```
1               Mod_WaveField      Wave field handling (switch) {1: use individual HydroDyn inputs
                                   without adjustment, 2: adjust wave phases based on turbine offsets
                                   from farm origin}

0               Mod_SharedMooring  Shared mooring system model (switch) {0: None, 3=MoorDyn}

"filename.dat"  SharedMoorFile     Name of file containing shared mooring system input parameters
                                   (quoted string) [used only when Mod_SharedMooring > 0]

0.01            DT_Mooring         Time step for farm-level mooring coupling with each turbine (s)
                                   [used only when Mod_SharedMooring > 0]
```

Figure 24. New inputs to FAST.Farm primary input file

3.4 Conclusion

The model implementation and documentation tasks were completed and made publicly available. The new capabilities work as expected. In a separate project, MoorDyn has been expanded to support bending stiffness for resolving loads on dynamic power cables [33]. This capability can be merged in to the FAST.Farm improvements to provide more detailed dynamics modeling of the full coupled shared mooring array including power cables during Task 3. OpenFAST, MoorDyn, and FAST.Farm can now be applied to shared mooring systems. A branch of FAST.Farm containing the new array-wide wave capability is publicly available on GitHub[2] and will be merged into the main OpenFAST release.

[2] https://github.com/mattEhall/openfast/tree/f/fast-farm

4 Dynamic Analysis and Design Refinement

With the preliminary design of the shared-mooring array completed and the FAST.Farm modeling capability updated to support shared moorings, the design can be evaluated considering its dynamic performance and any necessary design refinements can be made. Design constraints were previously checked with MoorPy using quasi-static methods and assumptions. Running load cases in FAST.Farm exposes the design to a range of unsteady loadings from wind turbulence and waves. It also includes turbine control, structural flexibility, and the drag and inertial characteristics of the coupled floating array and its moorings. As such, it is important for all assumptions and constraints to be re-checked at this stage to ensure that constraints are still satisfied and also that overdesigned components can be downsized to better minimize cost. An iterative process was taken to check the design dynamic performance, adjust the design accordingly using the quasi-static design algorithms, and repeat until the desired constraint tolerances were achieved.

The following subsections present the design load cases (DLCs) used in the dynamic analysis, the design refinement process, the simulation results, the revised shared-mooring and baseline array designs, and the final constraint checks across load cases to confirm performance with respect to platform offset and mooring constraints. An analysis of the behavior of the shared-mooring design in mooring-failure situations is also given. Lastly, a preliminary cost comparison is made between the shared-mooring and baseline designs.

4.1 Design Load Case Selection

The project requires a set of design load cases comprising the most relevant scenarios for evaluating the dynamic performance of the conceptual shared-mooring array design. Offshore wind standards like IEC 61400-3 describe a broad set of DLCs that cover many different conditions an offshore wind system could be exposed to. For the purposes of designing an array-level mooring system in this project, a small subset of DLCs was selected. This subset should cover the most consequential load cases for the design—for example, cases that produce the largest loads in the mooring system. This makes it possible to evaluate the design with fewer simulations so that design iterations can happen quickly.

For this project, where the focus is on the mooring system, there are two scenarios that are most consequential for the design: the regular operating condition under peak wind thrust, and an extreme 50-

year storm condition when the turbine is parked. The former reflects typical operating conditions when the wind speed is at the turbine's rated speed, along with the most probable corresponding sea state. The 50-year case reflects the worst-case conditions that have a statistical return period of 50 years, entailing strong winds, large waves, but the turbine shut down for safety. This case has reduced aerodynamic loads but much larger wave loads, resulting in a different type of loading than the operating case. An additional worst-case load case can be found by combining the 50-year wave condition with the rated-speed operating wind condition, resulting in the largest wave excitation and the largest wind thrust forces. Table 10 shows the parameters of the three load cases used in the project.

Table 10: Summary of DLCs used for the loads analysis and design refinement

Case Type	**Normal**	**Severe**	**50-year storm**
Turbine status	Operating	Operating	Parked
IEC DLC	1.1	-	6.1a
Return Period (yr)	< 1	-	50
Wind Speed (m/s)	11.4	11.4	37.8
Hs (m)	2.76	12.62	12.62
Tp (s)	12.16	19.96	19.96
Gamma	1.50	2.75	2.75
Wind Direction (deg)	-45, 0, 45	-45, 0, 45	-45, 0, 45
Wave Direction (deg)	-45, 0, 45	-45, 0, 45	-45, 0, 45
Partial Safety Factor	1.35	1.35	1.35

Each of the two load cases should be evaluated at different wind and wave headings to determine which loading directions are most severe. Given the perpendicular geometry and symmetries of the conceptual shared-mooring design, wind and wave headings were considered within a 90° range as shown in Figure 25. Within this range, three headings are most significant. The 0° heading causes loading directly inline with roughly half of the mooring lines in the array, likely resulting in the largest individual load increases. The 45° heading causes loading inline with the length of the array, potentially maximizing the accumulation of mooring tensions along the shared mooring lines. The -45° heading causes loading *across* the length of the array, potentially maximizing the loads on the anchors, especially if the anchors are considered shared.

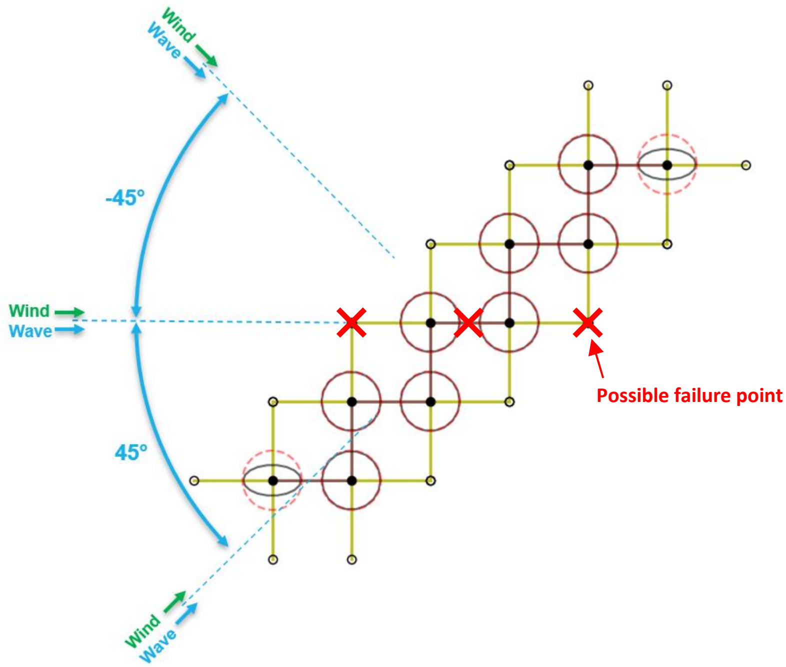


Figure 25. Wind and wave directions relative to array layout and three failure points

The design was evaluated under each of the wind and wave headings. Misaligned wind and wave conditions were also simulated initially and found to not be design driving, so they were excluded from later simulations. The three aligned headings were then used for subsequent DLC simulations. Turbulent wind conditions were generated by NREL's turbulence simulation preprocessor TurbSim to give wind data files for each wind condition and heading of interest [34], accounting for coherent turbulence across the array. Stochastic wave fields were generated using the functionality for JONSWAP wave spectra built into OpenFAST, and the additional features for coherent wave fields across the array described in Section 3.1.

The loads analyses also considered several failure modes that were expected to be design driving for the shared mooring system. The three selected failure points are shown by red 'X's in Figure 25. One failure point is the shared mooring line. Line failures in the middle of the array are expected to be the most consequential since they are farthest from the anchors at the end of the array that provide addition restoring. The other two failure points are at the anchor lines. The behavior of the array under these failure conditions helps determine whether the mooring system can be considered redundant or non-redundant, as described by ABS guidelines [35], which affects the safety factors used in the mooring design. Most importantly, these analyses check are important to ensure that one failure would not result in cascading failures throughout the shared array.

The selection of three sets of environmental conditions, three wind/wave headings, and three possible mooring system failure points defines the load cases that were simulated to check the mooring system performance. Additional fault cases, such as for turbine operation, were not within the scope of the project and are expected to have minimal impact on the mooring system design.

4.2 Initial Design Checks with OpenFAST and FAST.Farm

The floating wind turbine design information detailed in Section 1 and the mooring system designs detailed in Section 2 were combined to set up simulation models of the baseline individually moored design and the conceptual shared-mooring array design in OpenFAST and FAST.Farm, respectively. These models were then run through a range of checks to verify the expected simulation operation and dynamic performance. A dynamic power cable was also designed to include in the simulations at this stage. It is a 66 kV power cable, consistent with the power cables currently used on similarly sized floating wind farms such as Hywind Tampen, and more information is provided in Appendix A.2. However, the dynamic cable had negligible effect on the coupled system response so it was not included in the load case analyses for the sake of simulation speed.

4.2.1 Baseline Design Checks

The baseline design for an individual unit, consisting of the DTU 10 MW Reference Wind Turbine on a spar platform with three taut mooring lines was simulated through a range of tests in OpenFAST. These tests ensured that all parameters were reasonable and the mooring system was performing adequately. The outcomes are summarized below, and additional information about these checks is given in Appendix A.1.

Simulations without wind or waves were performed to check the structure’s equilibrium position. The baseline mooring system design from Task 2 was found to result in a heave offset of 6-7 meters upwards. To correct for this, the platform ballast was augmented by 260, resulting in a total platform mass of 12,770 tonnes, to bring equilibrium heave value back to zero.

The mooring line tensions under the unloaded condition were also checked and found to have very close agreement between OpenFAST/MoorDyn results and the previous tensions predicted by MoorPy. This helps verify MoorPy's accuracy and also indicates that some design assumptions are remaining valid in the dynamic analysis.

The system's mean offsets under a steady wind load were checked, with the model exposed to the rated wind speed, which produces a wind thrust force of 1.5 MN. In the OpenFAST simulation, the platform settled at an average surge offset of 57.5 meters and in the quasi-static analysis, the platform settles at a surge offset of 59.6 meters, both of which are less than the prescribed maximum surge offset of 60 meters. The reduced offset in the OpenFAST simulation is expected because the platform pitch results in a small reduction in the turbine thrust force, which was not modeled in MoorPy. The mooring line tensions in the rated wind conditions had similar levels of agreement.

Free decay simulations were run to check the system natural frequencies. The results, shown in Table 11 show that natural frequencies stay well outside the peak wave excitation frequencies and are reasonable natural frequencies for a spar platform, which further verifies the baseline design OpenFAST setup.

Table 11. Natural frequencies and periods from decay tests of all DOFs

Degree of Freedom	Natural Frequency (Hz)	Natural Period (s)
Surge	0.005	200.0
Sway	0.005	200.0
Heave	0.028	35.7
Roll	0.044	22.7
Pitch	0.044	22.7
Yaw	0.018	55.6

Lastly, the baseline design was simulated in OpenFAST under several stochastic wind and wave conditions to check for reasonable behavior, considering platform motions, turbine tower-base loads, and mooring tensions. In these simulations, the platform did not exceed any extreme value in any degree of freedom, meaning that it is well suited for the rated environment. The main mooring line tensions showed reasonable results, with maximum values that were only 20-30% of the line's minimum breaking load.

4.2.2 Shared-Mooring Conceptual Design Checks

The dynamic analysis of the shared mooring conceptual design involved simulating the floating array in FAST.Farm. Similar to how OpenFAST runs a simulation of a single wind turbine, FAST.Farm runs a simulation for an entire wind farm by coupling OpenFAST instances for each turbine. The shared-mooring array design was set up for simulation in FAST.Farm by expanding the input files of the baseline design with a primary FAST.Farm primary input file that defines the array layout and a farm-level MoorDyn input file that defines the shared mooring system. These input files are shown in Appendix A.3. Additional input files were made for FAST.Farm to provide the array-level wind inflow and the sea states corresponding to for each set of metocean conditions.

Figure 26 shows sample FAST.Farm platform motions for the ten-turbine shared-mooring array under the normal operating DLC with a 0° wind and wave loading direction.

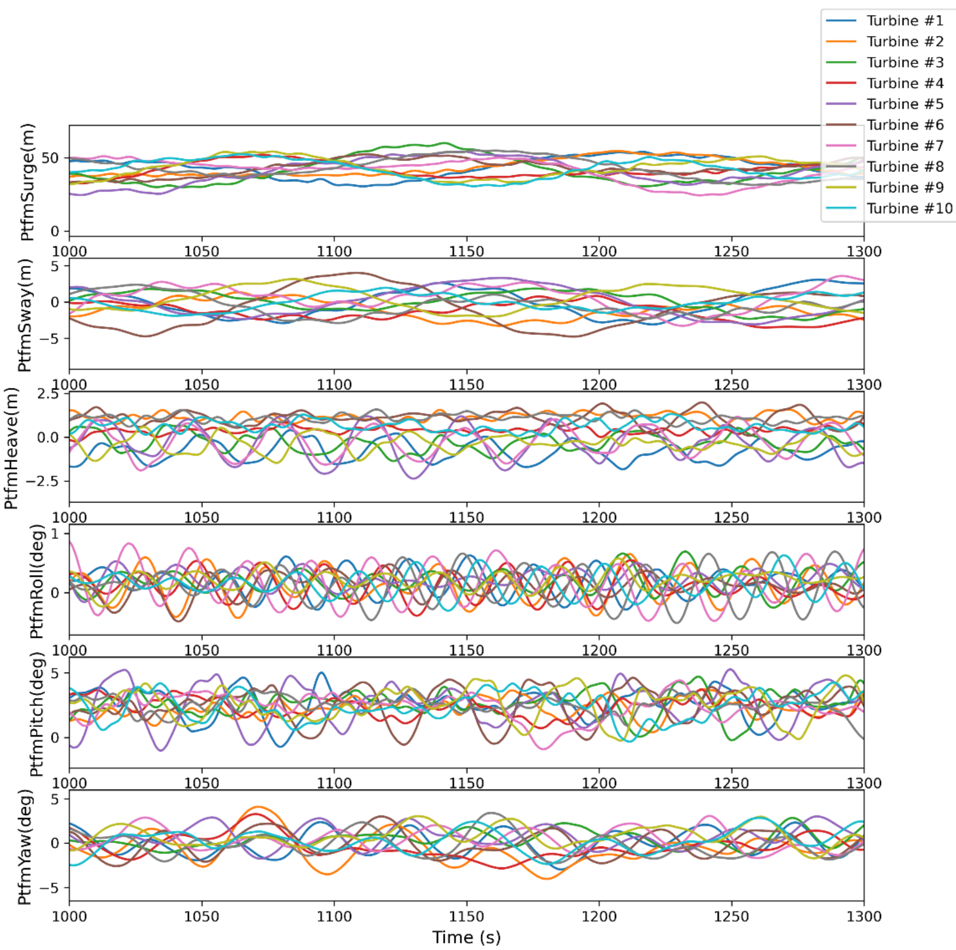


Figure 26. Sample platform motions for normal 0° DLC

Figure 27 shows the corresponding shared line tensions. The upwind/downwind shared line tensions have higher amplitude oscillations while the crosswind lines stay at a more consistent tension. Figure 28 shows sample anchor line tensions. As expected, the upwind lines have the highest tensions while the downwind lines have the lowest tensions. Similar to the shared lines, the crosswind anchor lines stay at a consistent tension while the upwind and downwind anchor lines have more variation.

Notably, the responses seen in the coupled simulations of the shared-mooring design do not include any problematic behaviors, such as resonances between turbines, which are potential concerns with shared mooring systems. Furthermore, the effect of second-order wave loads was found to be negligible in comparison to loads from wind turbulence. As such, the design is successful in avoiding any shared-mooring-specific dynamic response concerns.

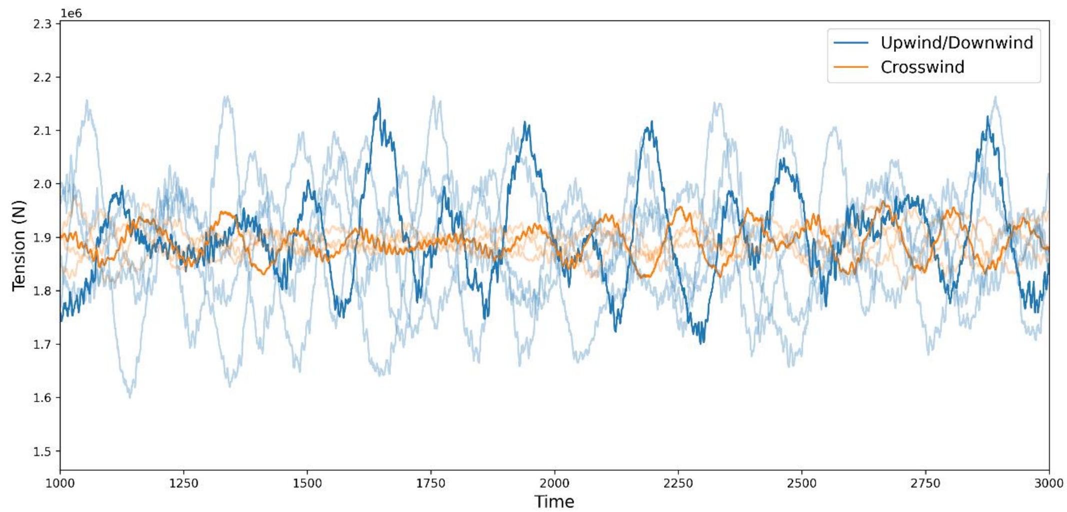


Figure 27. Sample shared line tensions for normal 0° DLC

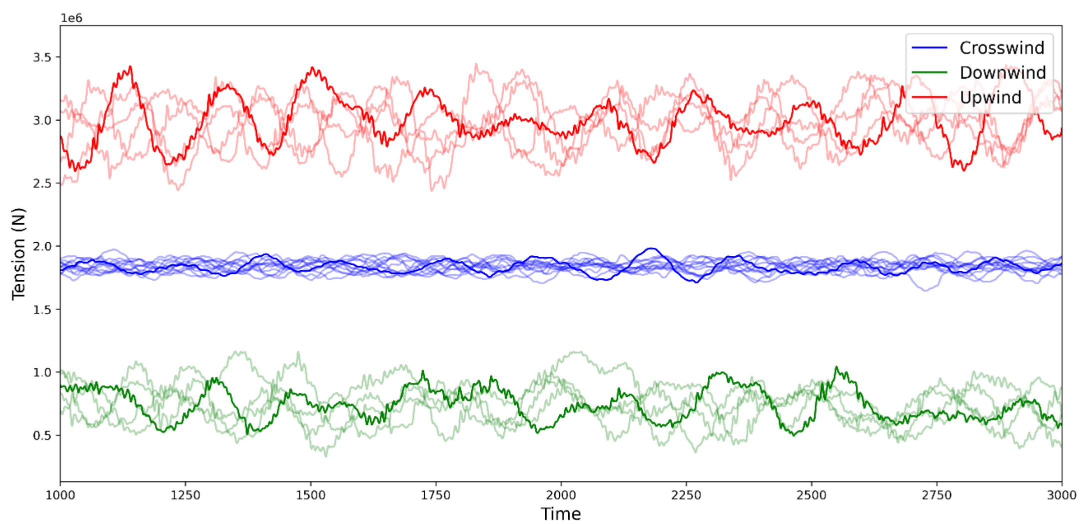


Figure 28. Sample anchor line tensions for normal 0° DLC

4.3 Mooring System Design Refinement

With the dynamic simulations set up for both the baseline and shared-mooring designs, the DLCs could be run and the constraints analyzed across these DLCs. Each load case and applicable wind/wave heading was simulated for the array for a duration of one hour, plus additional time at the beginning to allow startup transients to die out. The design constraints were then checked based on the extreme values found in the simulation time-series results. Based on the constraint results across load cases, the mooring designs were updated by rerunning the quasi-static sizing tools with updated assumptions, to iterate toward designs that satisfied all constraints by reasonable margins while minimizing cost.

After this iterative process was completed, a final adjustment was made to the mooring designs by evaluating the most design-driving load cases through multiple randomly seeded simulations to further ensure the designs meeting performance constraints. Six simulations were set up with different stochastic wind and wave realizations of the 50-year storm condition, which was design-driving for both the baseline and shared-mooring designs. The same wind and wave seeds were used for the baseline and shared-mooring designs to ensure that both designs were seeing the same loads, for each realization. Additionally, the window of time for start-up transients to settle was extended from 600 to 1000 seconds to exclude tension transients that were found in that range. Based on these additional load case results, the baseline and shared-mooring designs were fine tuned to more closely meet strength constraints across all the wind-wave realizations.

4.3.1 Baseline Design Refinement

The baseline array design provides a reference point for comparison in the exploration of shared-mooring arrays. It consists of turbines in the same positions as the shared array, but with each turbine individually moored using the baseline mooring design. The orientation of each turbine’s mooring system is rotated 180^{o} in every other row so that the mooring lines do not cross and maintain a safe clearance. Figure 29 depicts the ten-turbine baseline array.

Figure 29. Ten-turbine farm with baseline mooring configuration

FAST.Farm simulations were used to study the dynamics of the array and further refine the baseline design. These simulations for the baseline array were done with four turbines (Turbines 1-4) rather than ten to avoid a FAST.Farm bug in the outputs of larger numbers of turbines in non-shared arrays. The four-turbine farm still considers the same farm effects, including wake effects, and was determined to be an adequate representation of the full baseline farm given the lack of shared-mooring couplings. The results of the four turbine simulations are extrapolated for a ten-turbine baseline farm cost estimation. Additionally, baseline simulations were run with only a 0° wind/wave heading because this was determined to be the limiting condition, with anchor lines directly upwind and downwind. Because fewer turbines were simulated when refining the baseline design compared to the shared-mooring design, the baseline design keeps a larger margin from the safety-factor limits.

During the final design iteration, when checking the design-driving DLC across six different wind-wave realizations, the baseline design slightly exceeded tension constraints in one of the realizations. As the last design adjustment, the baseline design line diameter was increased slightly from 173 to 175 mm to stay within the allowed tension limit. After adjusting the line diameters in the baseline design, the line tensions were verified in all simulations. Figure 30 shows the maximum, mean, and standard deviation statistics of the maximum line tensions in each randomly-seeded simulation for the design-driving DLC. The maximum tension is at 96% of the allowed, showing the design satisfies design requirements across all six wind-wave realizations.

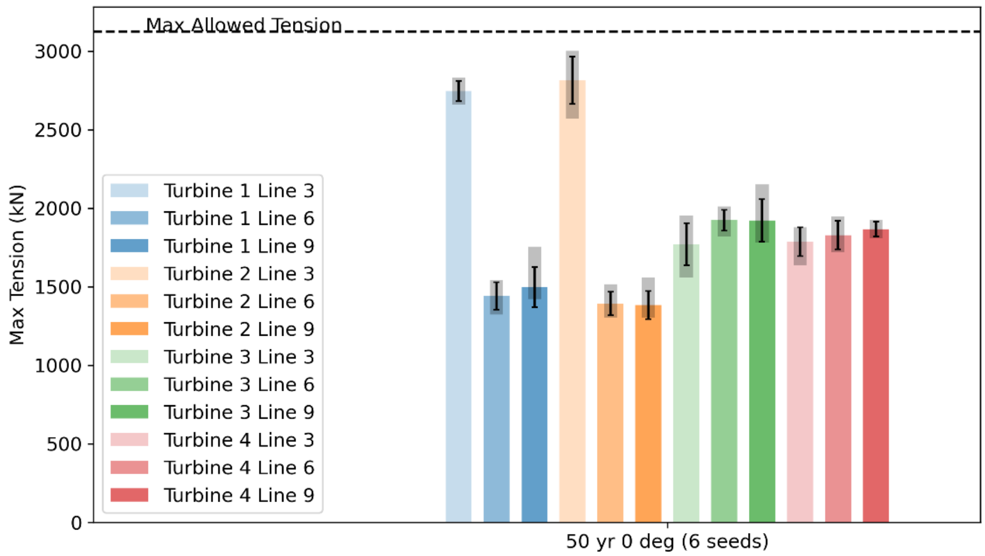


Figure 30. Statistics of tension maxima for the baseline design across six realizations

These statistics are for the maximum tension value seen in each anchor line of the baseline array across six wind-wave realizations for the 50-year storm DLC. Table 12 shows the parameters for the original baseline design from Table 6 and for the final refined baseline design.

Table 12. Original and refined baseline design parameters

	Original Baseline Design	*Refined Baseline Design*
Mooring arrangement	Taut-Rope with suction pile	Taut-Rope with suction pile
Mooring material	polyester	polyester
Horizontal spacing (m)	1600	1300
Number of lines in array	30	30
Diameter (mm)	175	175
Minimum breaking load (MN)	5.22	5.22
Segment lengths (m)	1599.1 (from anchor) 45.4 (bridle segment)	1328.5 (from anchor) 47.56 (bridle segment)
Anchor type	Suction Pile	Suction Pile
Number of anchors in array	30	30
Anchor holding capacity (t)	516	420
Total stationkeeping cost ($k)	31,710	27,950

The anchor spacing was reduced from 1600 m to 1300 m, which lowered line cost. The mooring line diameter was slightly reduced from 175 mm to 173 mm. The anchor sizing was updated using dynamic results, which reduced the maximum anchor capacity from 516 tons to 450 tons. In total, the refinement process reduced the overall cost from $31,710,000 to $27,950,000.

The following sections outline the offset and mooring constraints that were checked as part of the refinement process.

4.3.1.1 Final Constraint Checks for the Baseline Design

Figure 31 shows the mean and maximum offset for the four-turbine simulations in the relevant DLCs. The mean and maximum offsets are highest in the normal condition, with wind at rated speed and the turbine operating at peak thrust. The offset is much lower in the 50-year condition, as the blades are pitched 90° and the turbine is not operating. In the severe case, the larger wave-induced platform motions result in a lower thrust force than in the normal case, despite the same wind speed. In all load cases, the mean and max offset stay well below the requirement.

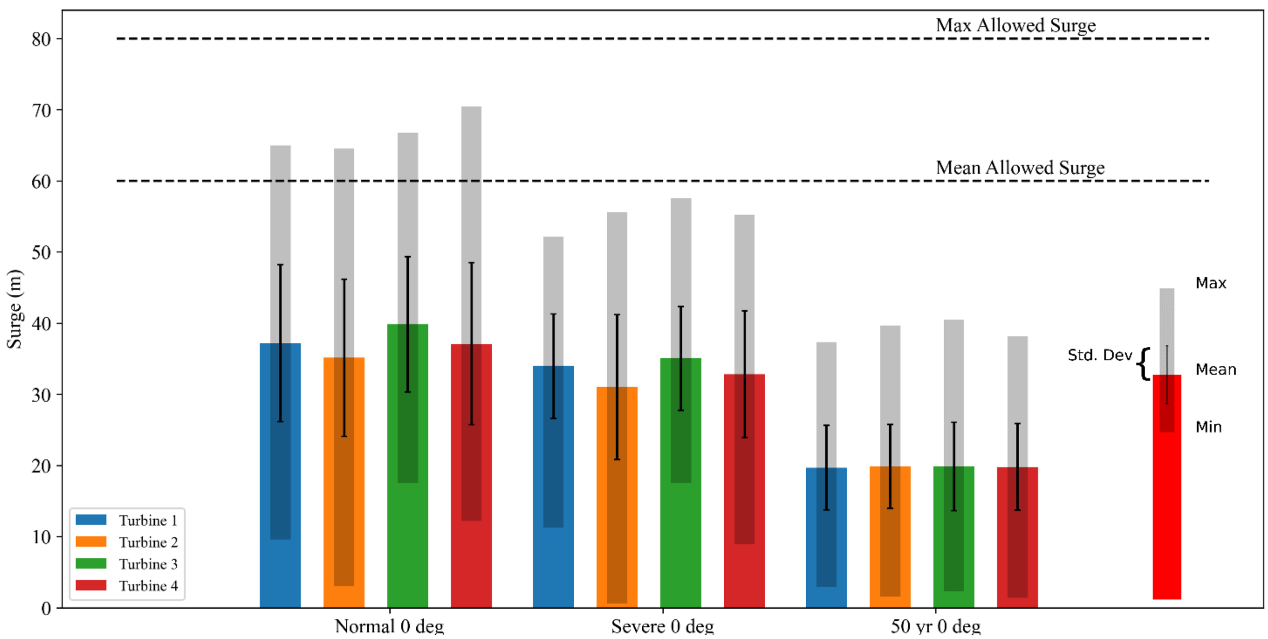


Figure 31. Surge statistics for four turbines of the baseline array

The maximum tension for each line is required to stay below the minimum breaking load of the line divided by a safety factor, which is 1.67 for dynamic simulations. Figure 32 shows the maximum tensions across the load cases. Turbines 1 and 2 have a completely upwind mooring line, which encounters the highest tension throughout the simulation. The mooring systems in Turbines 3 and 4 are rotated 180^{o}, which means they have a completely downwind mooring line and two semi-upwind mooring lines that encounter most of the tension. The maximum overall tension is consistently the upwind line for Turbine 2 in each DLC. The maximum tension is at 91% of the allowed fraction of the minimum breaking load, passing the requirement.

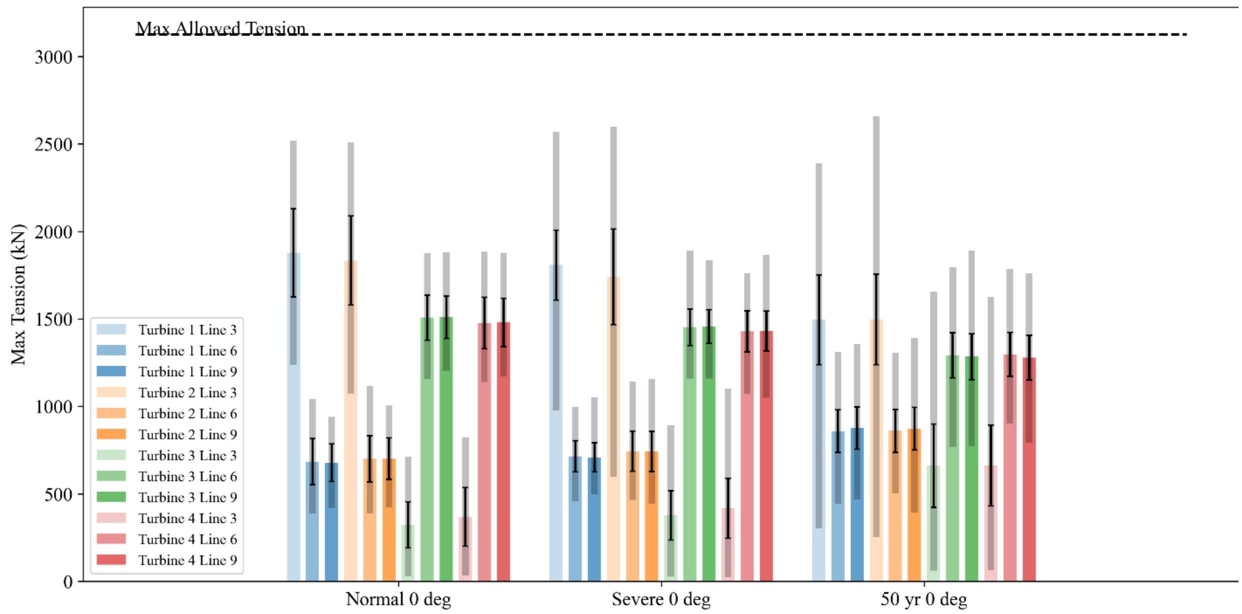


Figure 32. Mooring line tension statistics for four turbines of the baseline array

The baseline design is required to have no rope contact the seafloor. This is verified by checking the z position of the node closest to the anchor in FAST.Farm outputs. Figure 33 shows the first node's height above the seafloor for each line in each DLC. The minimum rope contact is 11 m and is seen in the downwind line of turbine 3 in the normal operating case. This passes the rope contact requirement.

During the baseline design refinement process to include the dynamics of the system, the FAST.Farm simulations sometimes encountered an extreme yawing phenomenon, which would consequentially cause extreme motions in the other degree of freedoms and abort the FAST.Farm simulation. It was determined that this phenomenon is a result of designs with a low yaw stiffness of each turbine, which would cause the simulation to stop short of its desired run time.

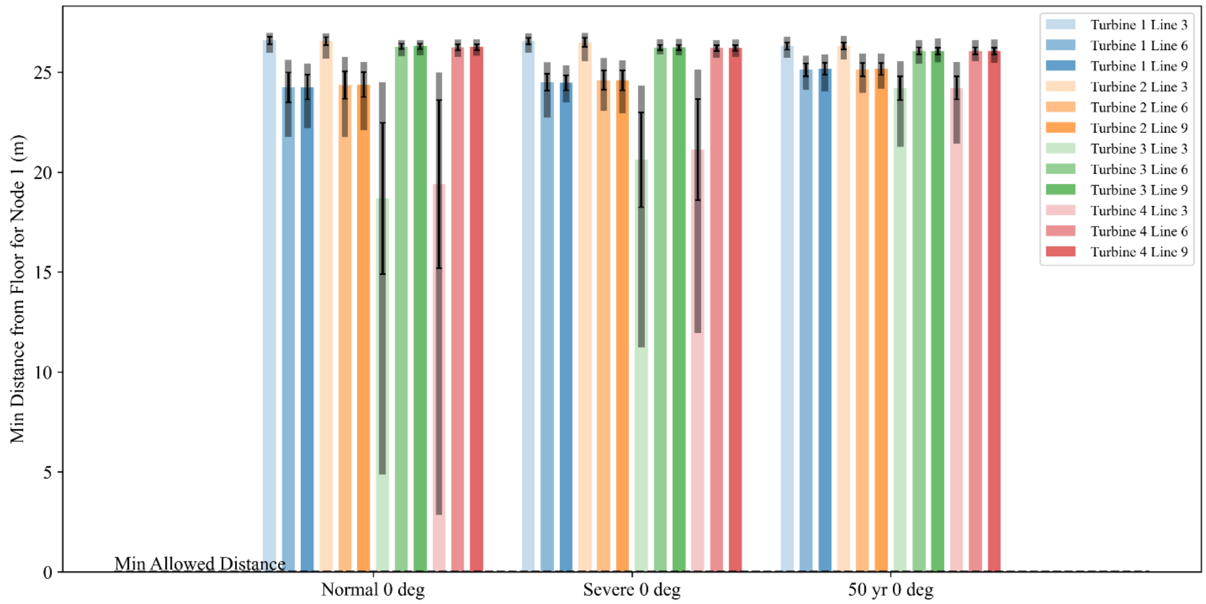


Figure 33. Rope contact checks for four turbines of the baseline array

Methods taken to increase the yaw stiffness of the design include increasing the tautness of the line, mainly increasing the anchor spacing and decreasing the line length, or increasing the fairlead radius of the spar platform. There is room for the bridle mooring lines to connect to the spar via small appendages that protrude from the main spar, which increases the mooring yaw stiffness. These steps were taken to increase the yaw stiffness and avoid the simulation instability. As such, the dynamic analysis done with FAST.Farm produced a new constraint on the design process that was not seen in the previous quasi-static design process. The limits to this constraint are not in the scope of this study but would be a worthy topic of investigation in future analyses.

4.3.2 Shared Mooring Design Refinement

As with the baseline design, FAST.Farm loads analyses of the different DLCs and relevant wind-wave directions were used to iteratively refine the shared-mooring design to minimize cost while meeting the design constraints across all load cases.

During the final design iteration, when checking the latest design in the design-driving DLC across six different wind-wave realizations, the anchor lines were exceeding the allowed tension. As a result, their diameters were increased from 205 to 209 mm in the final adjustment. With the longer duration at the start of the simulation discarded to avoid start-up transients, the shared lines from were shown to be overdesigned. To improve cost savings, the shared line diameter was reduced from 168 mm to 163 mm.

After these adjustments, the updated mooring design's line tensions were checked against constraints in the six wind-wave realizations. Figure 34 shows the statistics of maximum anchor line tensions across the six randomly seeded simulations, and Figure 35 shows the same for shared line tensions. The maximum anchor line tensions are below 97% of allowed in all simulations. The maximum shared line tensions are a larger margin below the allowed tension in all six simulations.

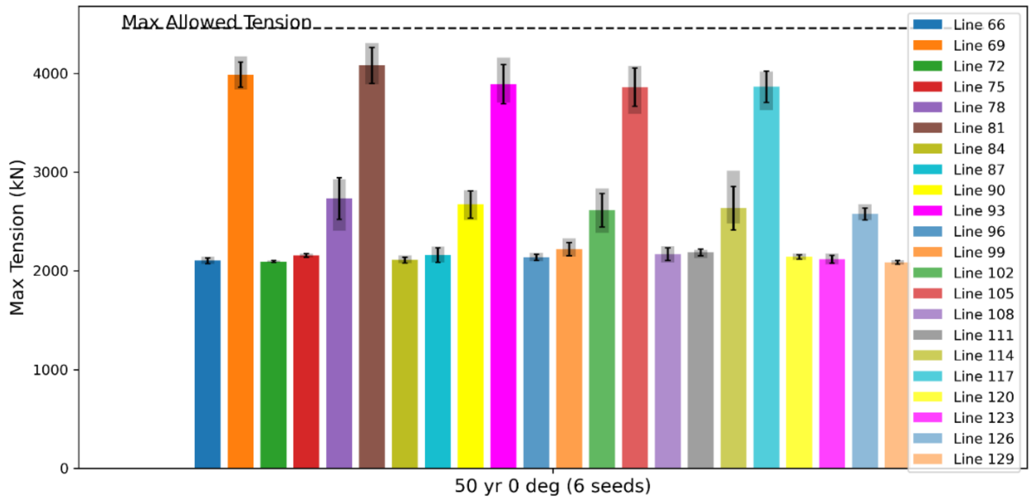


Figure 34. Statistics of tension maxima for the shared-mooring array anchor lines in 50-year DLC

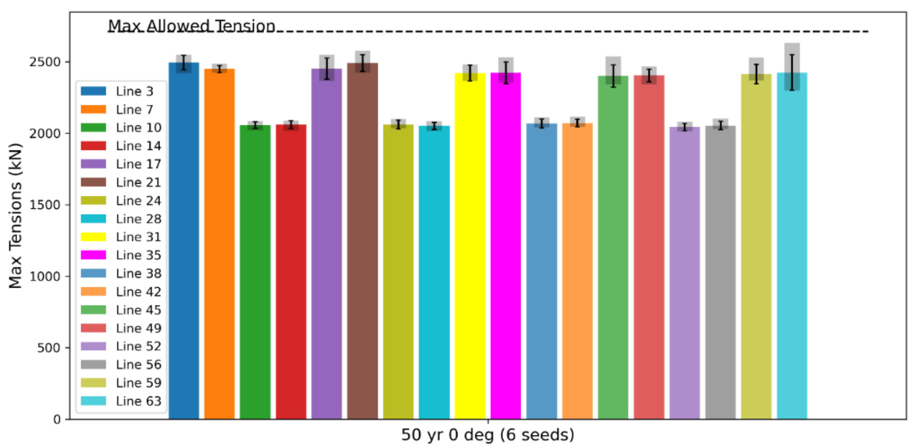


Figure 35. Statistics of tension maxima for the shared-mooring array shared lines in 50-year DLC

Table 13 shows the parameters for the original shared-mooring design from Table 6 and the final refined shared-mooring design. Over the design refinement process, the diameters of the shared lines and the anchor lines were reduced to 168 and 205 mm respectively. The clump weight mass was reduced from

100 t to 80 t. These design changes, along with other dynamic effect constraint checks, reduced the total cost from $32,180,000 to $27,090,000.

Table 13. Original and refined shared mooring system design

	Original Design		*Refined Design*	
Mooring arrangement	Shared-Rope with 2 weights	Taut-Rope with suction pile	Shared-Rope with 2 weights	Taut-Rope with suction pile
Mooring material	polyester	polyester	polyester	polyester
Horizontal spacing (m)	1600	1600	1600	1600
Number of lines in array	9	22	9	22
Diameter (mm)	200	213	163	209
Minimum breaking load (MN)	6.80	7.73	4.53	7.45
Clump weight mass (t)	100		80	
Segment lengths (m)	1363.3 (mid span) 54.6 (above clump) 45.4 (bridle segment)	1594.7 (from anchor) 45.4 (bridle segment)	1314.6 (mid span) 55 (above clump) 48.55 (bridle segment)	1587.1 (from anchor) 47.35 (bridle segment)
Anchor type	(Shared Line)	Suction Pile	(Shared Line)	Suction Pile
Number of anchors in array		22		22
Anchor holding capacity (t)		763		578
Total stationkeeping cost – without shared anchors ($k)		32,180		27,090

4.3.2.1 Final Constraint Checks for the Shared-Mooring Design

The offsets for each turbine are required to stay below a max offset of 80 m and a mean offset of 60 m for every DLC. From FAST.Farm outputs, the offset for each turbine was found by calculating the hypotenuse of surge and sway. The mean and max offset can be adjusted by increasing or decreasing mooring stiffness. Figure 8 shows the mean and max offset for each turbine across the different DLCs. The design passes both mean and max offset checks in all the DLCs. The highest mean and max offset are in the normal load case because the operating turbine experiences the highest amount of thrust. The turbines are parked in the 50-year storm, so the blades are fully pitched, reducing the thrust force as much as possible.

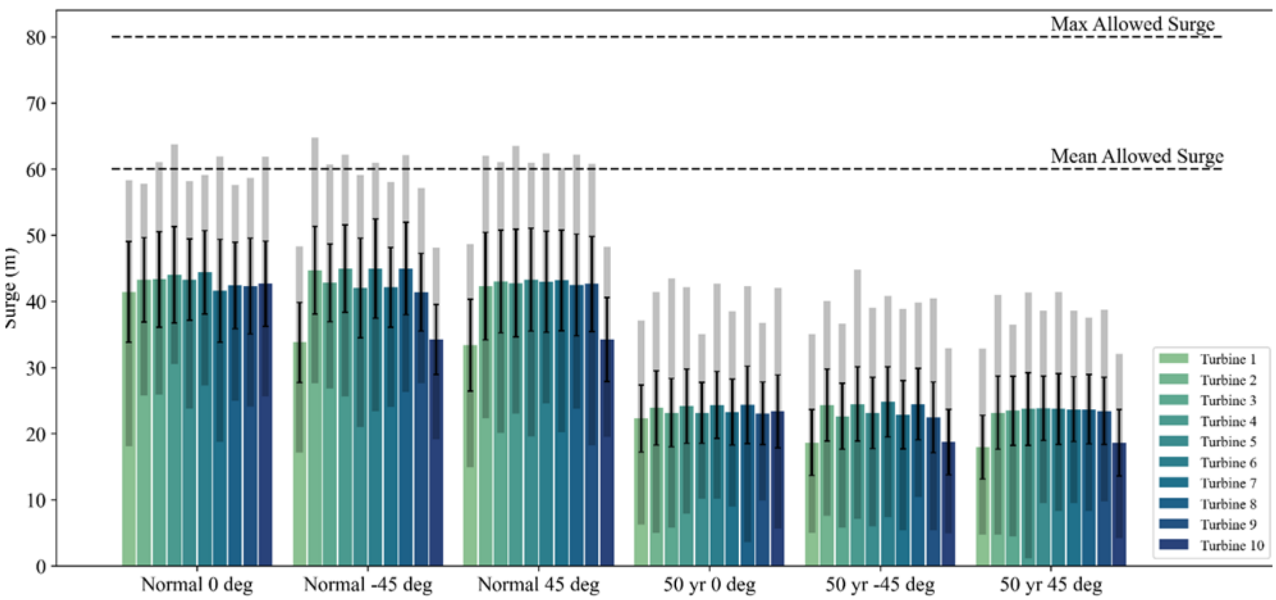


Figure 36. Surge statistics for the shared-mooring array

The maximum tensions for all mooring lines must stay below the MBL by the specified safety factor. The safety factor for intact dynamic simulations is 1.67 based on API RP-2SK. The diameter of the mooring lines can be increased to increase the MBL and reduce the tensions. Figure 37 shows the mean and max tensions for the anchor lines in the different DLCs. The max tensions stay below the required threshold in all conditions. The normal 0° condition has the highest average tensions due to the high average offsets, though the 50-year 0° condition has the highest maximum tensions. Figure 38 shows the shared line tensions for the segments above the clump weight. The average tensions are consistent across the different load cases, likely because the turbines generally move synchronously. The highest shared tensions are seen in the 50-year 0° condition, but the tensions pass requirements in all cases.

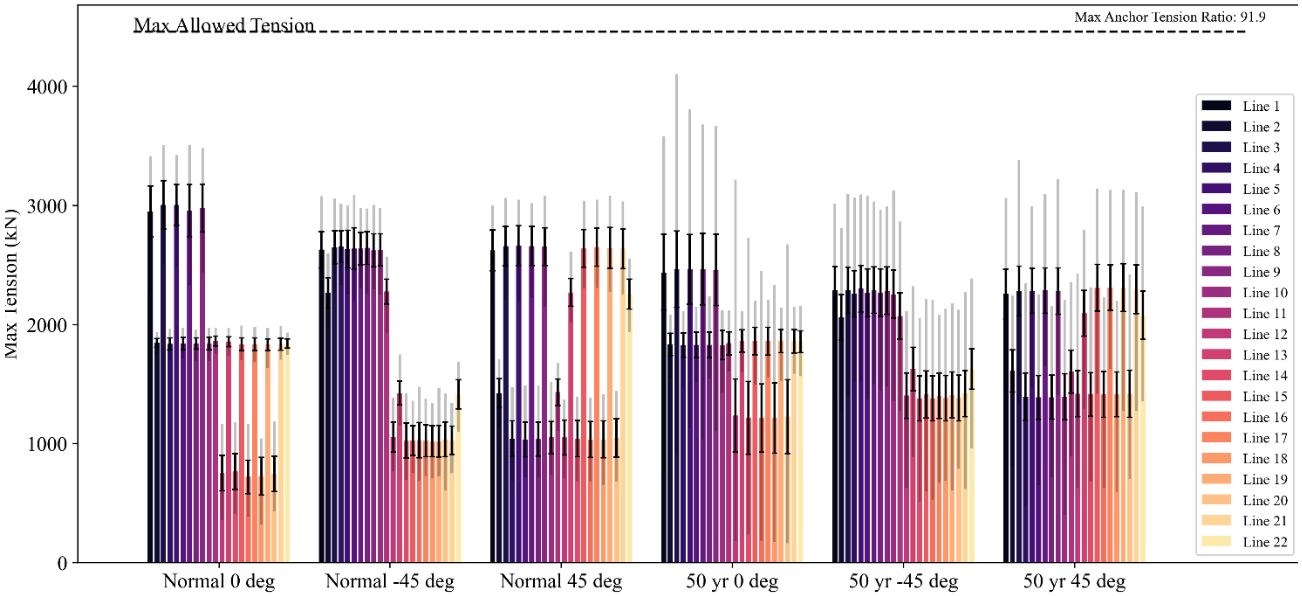


Figure 37. Anchor line tension statistics for the shared-mooring array

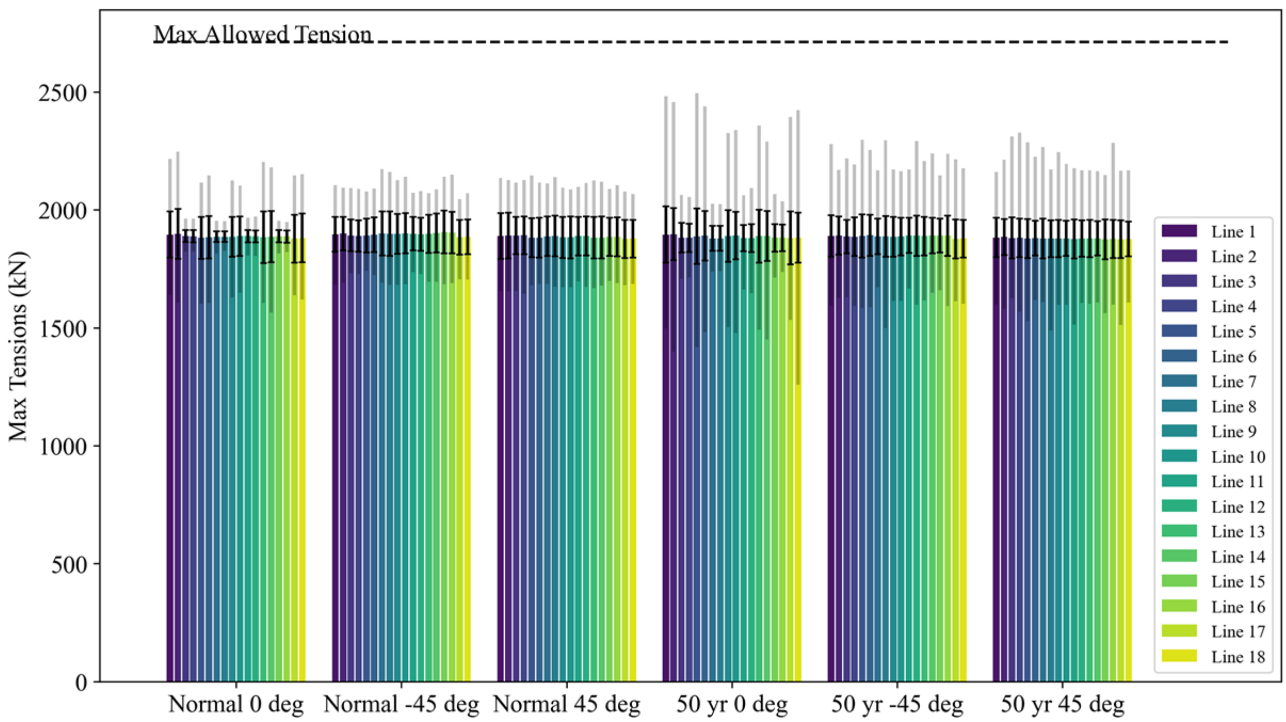


Figure 38. Shared line tension statistics for the shared-mooring array

The rope contact check requires the anchor lines to have no contact with the seabed. This can be verified by checking the z position of the node closest to the anchor and ensuring that it stays above the seabed. Figure 39 shows rope contact across the DLCs. The minimum distance from the floor is 15 m in the normal 0° condition. This requirement is safely met. The final mooring check is that the midpoint depth of the share lines stays beyond 60 m from the water surface. This is verified by checking the z position of the center node on the shared lines. Figure 40 shows the distance for the shared lines across the various load cases. The minimum distance is 66.6 m, which passes the 60 m requirement.

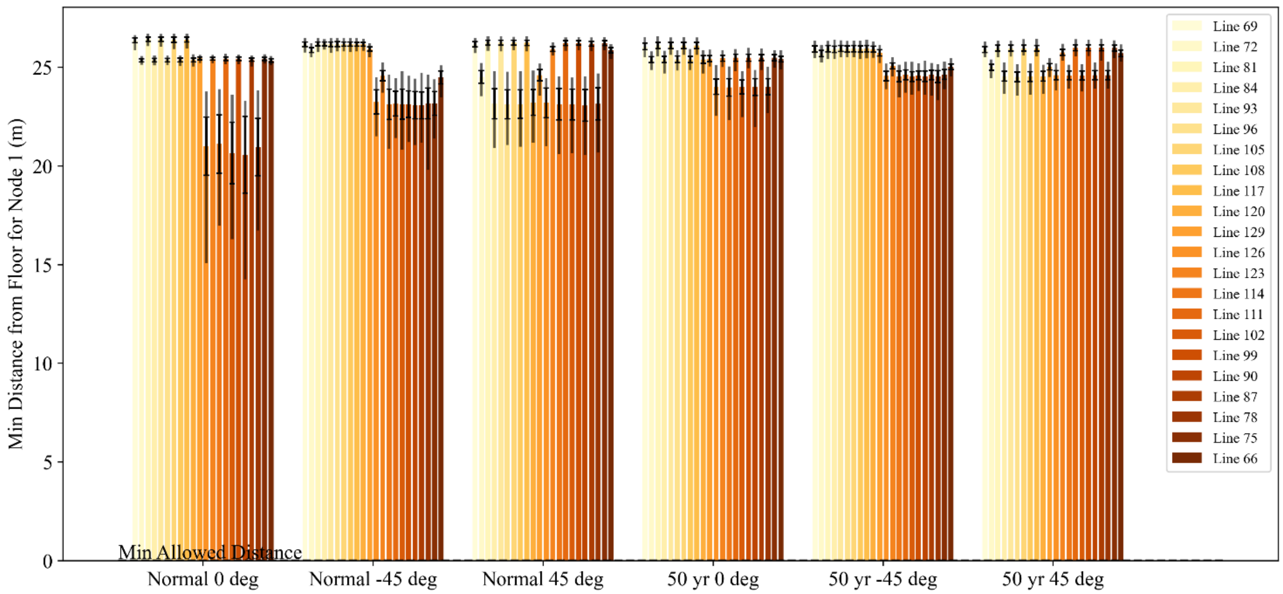


Figure 39. Rope contact statistics for the shared-mooring array

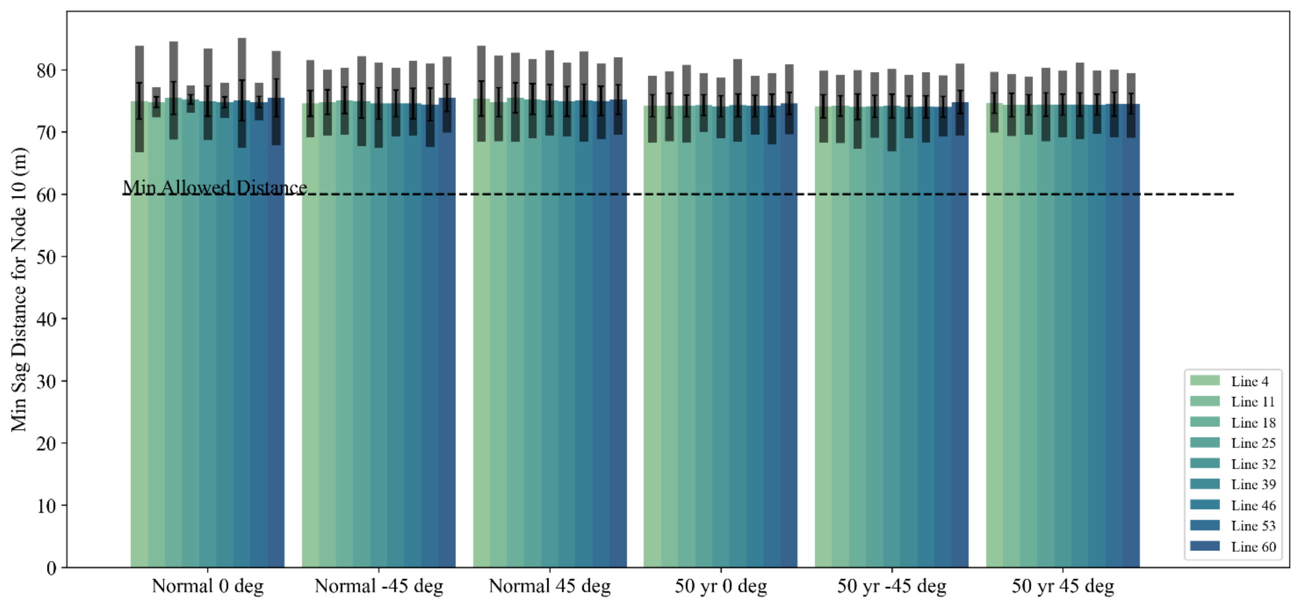


Figure 40. Shared line midpoint depth statistics for the shared-mooring array

4.3.2.2 Anchor Capacity Calculation and Shared-Anchor Design

Anchor loads are not checked as a constraint because the anchors are sized to the maximum loads seen in the simulations. However, anchor loads and the resulting anchor sizing do have a significant impact on the total cost of the mooring system. Both individual and shared anchor options were considered for the final cost calculation.

The process for sizing the anchors is based on the anchor loads predicted by FAST.Farm simulations and the suction pile anchor safety factors specified in API RP-2SK. From the FAST.Farm time series outputs, horizontal loads are scaled by a factor of 1.6 and vertical loads are scaled by a factor of 2, then the resultant of these load components is computed for each anchor to estimate the required capacity of each suction pile throughout the simulation.

$$\text{Anchor capacity} = \max\left(\sqrt{\left(1.6\, F_{xy}(t)\right)^2 + (2.0\, F_z(t))^2}\right)$$

The peak capacity calculated across all anchors and across all load cases determines the uniform anchor capacity used in the design.

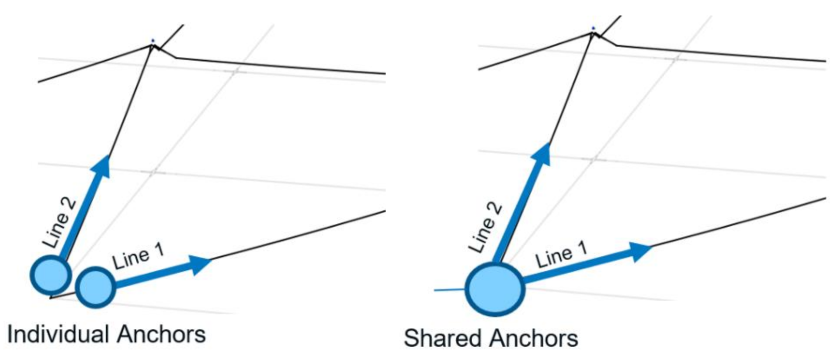


Figure 41. Shared anchor example

Two anchor configurations were considered for the shared mooring array: the configuration with all individual anchors presented in Table 13, and a configuration that makes some of the anchors shared. Anchor capacity and cost were calculated for both anchor configurations. The shared anchor loads were calculated by summing the forces from both attached mooring lines on an anchor (Table 14). Figure 42 shows the individual and shared anchor capacity across the DLCs. The shared anchors have the highest capacity with the maximum seen in the normal DLC with a -45° wind and wave heading. The individual anchors are at maximum capacity in the normal 0° wind and wave heading, with anchor lines directly upwind.

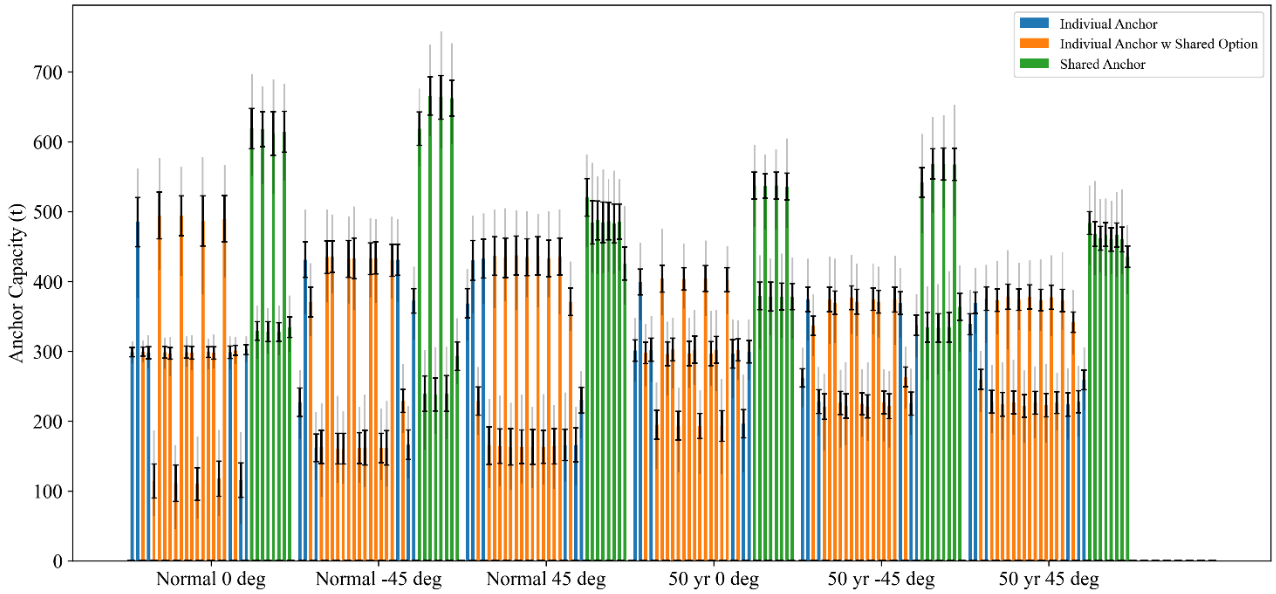


Figure 42. Anchor capacity requirement statistics for the sharing-mooring array

The orange bars are for individual anchors along the sides of the array. The green bars are for when these anchors are shared. The blue bars are for the anchors at the ends of the array that are always individual.

Table 14 shows the resulting anchor capacity for the different shared mooring arrangements. The individual anchor arrangement has a total of 22 anchors with a capacity of 578 t. The shared anchor arrangement has 6 anchors with a capacity of 556 t and 8 anchors with a capacity of 782 t for a total of 14 anchors. The shared anchors significantly reduce cost because a shared 782 t capacity anchor replaces two individual 578 t capacity anchors. The summed anchor capacity is reduced by 15%.

Table 14. Anchor capacity for the two shared mooring anchor arrangements

Anchor Capacity (# of anchors)		Limiting Condition
All Individual (22)	578 t	Normal 0°
Individual (6)	556 t	Normal -45°
Shared (8)	782 t	Normal 0°

4.3.2.3 Failure Cases

The behavior of the shared-mooring array design was checked under mooring line failure scenarios to ensure that the shared configuration did not introduce new risks, such as cascading failures where one failure causes additional failures. The baseline to compare against is a conventional three-line mooring system, where failure in one of the lines will not put the other lines at risk but will allow significant platform offsets. Generally, a line failure in the baseline case would allow surge offsets of nearly the anchor spacing distance.

In the shared-mooring case, three failure points were analyzed using both quasi-static MoorPy analyses and dynamic FAST.Farm simulations. While modeling assumptions in FAST.Farm do not fully capture all aspects of the transient response in a failure case, the worst-case mooring line tensions are expected to be accurate. Results from all analyses indicate that mooring line tensions stay below the mooring line MBLs, thereby satisfying the strength criteria in API RP-2SK for a line failure (with safety factor of 1). This confirms that the shared-mooring design is not at risk of cascading failures.

Evaluating the worst-case offsets of the shared-mooring design reveals beneficial characteristics relative to conventional designs after a line failure. After a mooring line failure, there is potential for platform offsets to overshoot due to momentum before settling into their post-failure equilibrium states. However, FAST.Farm simulations showed that the overshoots are small and do not have a noticeable effect on extreme values relative to wind- and wave-induced motions. In fact, the range of extreme offsets from dynamic results is bracketed by two quasi-static analysis cases: a line failure under no load, and a line failure under full rated thrust. To illustrate, in the case of an upwind anchor line failure, FAST.Farm simulation of 50-year-storm conditions predicts a peak offset of 390 m, while MoorPy analysis predicts an offset of 200 m under no load and 580 m under rated thrust load.

The quasi-static analysis of system equilibrium after a shared line failure is illustrated in Figure 43, with the colors indicating the states before failure and after failure under the two load scenarios. In this scenario, the downwind turbine experiences the largest offsets, at 505 m, while the offset of the upwind turbine is minimal.

The same analysis for an upwind anchor line failure (the worst case) is illustrated in Figure 44. In this scenario, the upwind turbine experiences the largest offsets, at 580 m under rated thrust conditions. This represents the worst-case offset in the array, especially considering that turbines would typically be parked during extreme conditions and after a failure.

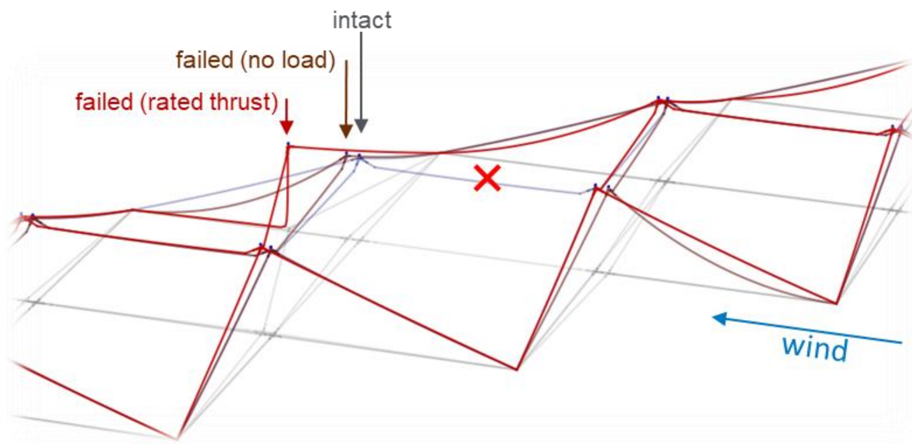


Figure 43. Equilibrium after shared line failure

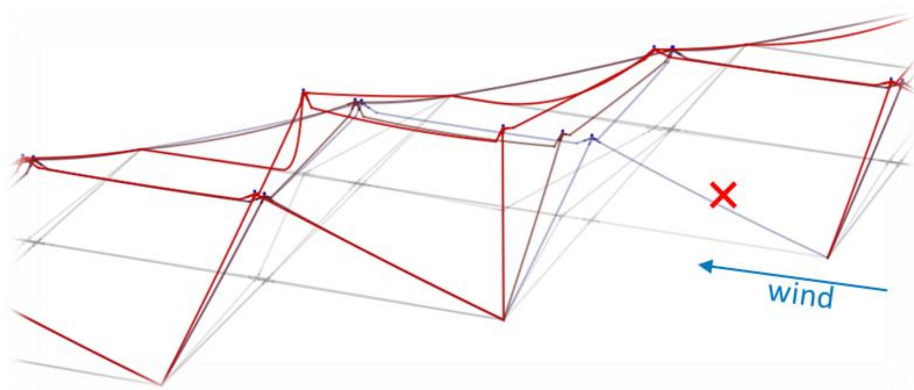


Figure 44. Equilibrium after upwind anchor line failure

In mooring line failure scenarios, the maximum offsets of the shared-mooring design are less than half of those of the baseline design. This could mean a significant reduction to the risk for power cables and the complexity of repair operations. Essentially, the shared-mooring design, with its use of four lines per turbine, offers a degree of redundancy not seen in the baseline three-line mooring configuration.

4.4 Conclusions

The baseline and shared-mooring array designs developed using quasi-static tools earlier in the project have now been evaluated and refined using coupled dynamics simulations from FAST.Farm. In this refinement process, constraints on mooring system loads and platform offsets were checked with FAST.Farm simulations of three load cases and three loading directions. Tuning factors in the quasi-static design algorithms were then adjusted based on the dynamic constraint checks to generate new design iterations. The switch to dynamic analysis resulted in significant changes to some components sizings—most notably a reduction in the shared line diameters. It also brought up a dynamic stability issue in both the baseline and shared designs that necessitated a modest increase in the fairlead attachment radius. Overall, the design iteration process involved over 20 iterations to converge on the refined designs.

Refinement of the baseline design saw a total stationkeeping cost reduction from $31.7M to $27.9M for the 10-turbine array. Refinement of the shared-mooring design saw a larger reduction from $32.2M to $27.1M. Additionally, a design variation with shared anchors achieves a significant cost reduction, resulting in $20.7M for the combined shared-mooring and shared-anchor solution. This is a greater-than-25% cost reduction over the baseline design.

Simulating the shared-mooring design across a wide range of load cases, including three failure cases, did not bring up any problematic phenomena from the shared configuration. This demonstrates that, although shared mooring systems can make system response more complex, the selected conceptual design succeeds in mitigating any potential for resonances thanks to its unique staggered layout. In mooring failure cases, the shared-mooring design shows significant advantages. Without additional strengthening, it satisfies strength constraints and offers a degree of stationkeeping redundancy. Compared to conventional three-line moorings, the shared-mooring design has significantly smaller offsets after a line failure, which could translate into significant benefits for larger-scale arrays where failure probabilities increase.

5 Performance and Cost Comparison

This section presents a comparison of the final baseline and shared-mooring designs, including their technical performance and their levelized cost of energy (LCOE). The previous loads analysis is extended with a comparison of tower base bending moments and damage-equivalent loads. The LCOE is estimated for the shared-mooring and baseline designs using NREL's ORBIT [19] and FLORIS [36] tools. Additional LCOE cost assumptions are documented. The potential cost implications of the shared mooring design's redundancy advantages are also characterized by estimating the cost of a comparable baseline design with four mooring lines.

5.1 Loads Comparison

Additional investigation of loads beyond the extreme mooring loads discussed in Section 4 is relevant to ensure that the shared mooring system does not add any detrimental loads to the turbines or cause unexpected fatigue load increases in the mooring components.

5.1.1 Tower Base Bending Moment

The tower-base bending moment is an important metric for the loads on a floating wind turbine caused by platform motions. It will typically see the largest loads from wind- and wave-induced platform motions in the fore-aft bending moment direction. Table 15 shows the maximum and standard deviation for the tower-base fore-aft bending moment for each turbine in each condition. The maximum bending moments are comparable between the baseline and shared-mooring designs, with the shared mooring arrangement reducing the bending moment as much as 12.9%. Similarly, the standard deviation of the bending moment is similar in the baseline and shared-mooring design, with the shared-mooring design producing a generally lower standard deviation. This analysis shows that the shared mooring arrangement does not significantly affect the tower loads, making it likely that the other loads higher up in the turbine are similarly unaffected.

Table 15. Tower-base bending moments of baseline and shared-mooring designs

		Maximum			Standard Deviation		
		Baseline (MN-m)	Shared Mooring (MN-m)	% Change from Baseline	Baseline (MN-m)	Shared Mooring (MN-m)	% Change from Baseline
	Normal	341.3	331.6	-2.84%	57.92	59.00	1.86%
T1	Severe	472.7	477.5	1.02%	100.43	98.96	-1.47%

	50 Year	553.7	544.9	-1.59%	181.05	164.21	-9.30%
T2	Normal	324.0	313.1	-3.36%	53.88	53.12	-1.40%
	Severe	438.4	437.3	-0.25%	108.51	106.20	-2.13%
	50 Year	652.1	611.9	-6.16%	182.84	164.68	-9.94%
T3	Normal	312.9	331.7	6.01%	54.61	55.21	1.09%
	Severe	452.7	432.7	-4.42%	98.80	96.57	-2.26%
	50 Year	697.5	607.4	-12.92%	185.44	163.28	-11.95%
T4	Normal	296.8	313.4	5.59%	50.98	52.14	2.28%
	Severe	402.7	410.6	1.96%	97.79	96.17	-1.66%
	50 Year	677.9	619.3	-8.64%	185.68	162.59	-12.44%

5.1.2 Mooring Line Damage Equivalent Loads

Damage equivalent loads (DELs) are a measure of the magnitude of fatigue loads on a structure. Fatigue is a driving concern for steel components of a mooring system. The mooring arrangements in this study are predominantly composed of polyester lines; however, it is assumed that there would be chain components at the anchor and platform connections, and steel triplate components at the bridle and clump weight connection points. These steel components were not modeled in FAST.Farm, however a DEL analysis was carried out to understand the effects of the shared mooring configuration on fatigue loads.

Tension outputs where the mooring lines attach to the anchors and to the floating platforms were measured during the FAST.Farm simulations. NREL's pCrunch tool was used to estimate DELs with an assumed fatigue slope of 5 for steel, to represent the loads on short chain segments or steel connector hardware at these locations. For comparison, the DELs for the anchor lines directly upwind of a turbine were averaged within the baseline array and the shared-mooring array for each condition. Similarly, the DELs for the anchor lines directly downwind of a turbine were averaged. The upwind and downwind shared line DELs for the shared-mooring array were averaged separately. The bridle lines directly upwind of T2 and T4 were averaged as the upwind shared lines and the bridle lines directly downwind of T1 and T3 were averaged as the downwind shared lines The crosswind or partially crosswind lines (seen in the baseline design) were left out of the analysis due to the differences in the baseline and shared-mooring line orientations. Additionally, the DELs were normalized by dividing the calculated DEL for each line by the line's minimum breaking load.

Table 16 shows the normalized DELs at the anchor and platform connection points, subdivided further into upwind and downwind averages for each condition. The anchor connection points have consistently lower DELs than the turbine connection points, as the anchor connection points see lower tensions than the platform connection points. Similarly, the downwind lines have lower DELs than the upwind lines. The shared line DELs are similar to the anchor line DELs, showing that the shared lines do not experience significant additional fatigue loads. In the normal and severe conditions, the shared mooring arrangement generally has a lower DEL at both the anchor and platform connection points. A lower DEL would allow smaller-diameter chain components, suggesting potential cost savings in the shared mooring arrangement.

The 50-year storm condition consistently shows the highest damage, likely due to the turbulent motions seen in that condition. Notably, the shared-mooring DEL at the upwind turbine connection in the 50-year condition is 600% greater than the baseline DEL. While this is an extreme difference, fatigue on a structure is cumulative over the design lifetime. Given that the 50-year condition would occur very rarely in the design life of the wind farm, this high damage equivalent load was not considered a concern.

Table 16. Baseline and shared-mooring DELs at anchor and turbine connection

	Normalized Average DEL at Anchor Connection Point			Normalized Average DEL at Turbine Connection Point			Shared Lines Normalized Average DEL
	Baseline	Shared Mooring	% Change from Baseline	Baseline	Shared Mooring	% Change from Baseline	Shared Mooring
Upwind							
Normal	0.0129	0.0092	-28%	0.0090	0.0068	-24%	0.0047
Severe	0.0125	0.0107	-14%	0.0129	0.0091	-29%	0.0074
50 Year	0.0107	0.0126	18%	0.0195	0.1347	592%	0.1160
Downwind							
Normal	0.0080	0.0073	-8%	0.0044	0.0046	3%	0.0040
Severe	0.0105	0.0096	-8%	0.0070	0.0077	10%	0.0063
50 Year	0.0126	0.0104	-17%	0.0119	0.0124	4%	0.0155

5.2 Stationkeeping Cost Comparison

Cost reduction was the driving force behind design refinement for both the shared-mooring and baseline designs. Using the cost assumptions laid out in Section 2.4, a preliminary cost estimation was calculated for each design. Table 17 reiterates the cost assumptions for the various mooring components, installation, and decommissioning.

Table 17. Cost assumptions

Mooring Component	Cost
Chain	$2,585 per MT weight
Polyester Rope	$0.162 per MT break strength
Clump Weight or Float	$1,000 per MT weight
Suction Pile	$1,080 per MT of anchor capacity
Suction Pile Installation	$212 k per anchor
Suction Pile Decommissioning	$148 k per anchor

The resulting stationkeeping cost estimates for the refined baseline and shared mooring designs, as well as the shared mooring and anchor design, are presented in Figure 45 and Table 18.

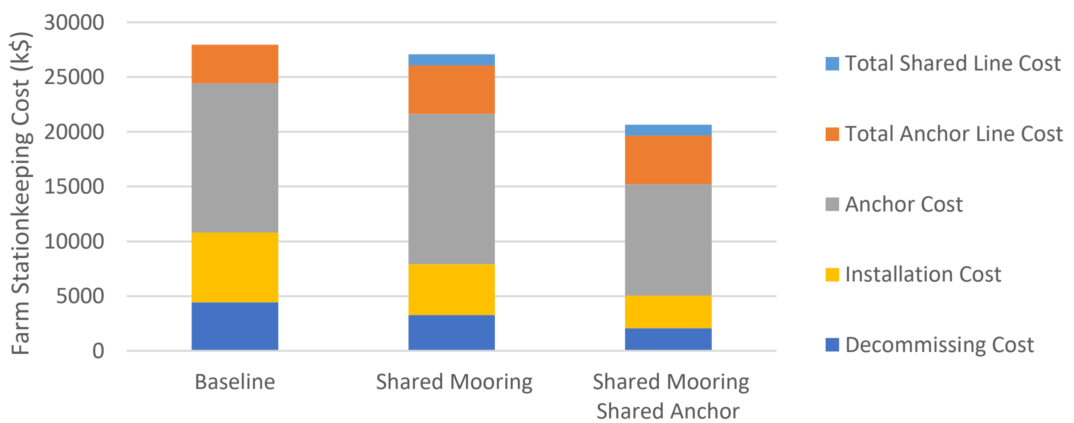


Figure 45. Stationkeeping cost comparison of the baseline, shared-mooring, and shared-mooring-and-anchor designs

From these cost assumptions, the refined baseline cost is $27,950,000, which is about 3.2% more expensive than the shared mooring design without shared anchors. For both designs, the anchor cost is a significant component of total cost. Shared anchors are a promising source of cost reduction because they lower the total number of anchors for installation and decommissioning costs. Based on the preliminary cost analysis, shared anchors reduce the total cost of the shared mooring array by 26%.

Table 18: Stationkeeping cost breakdown of the final mooring system designs

	Baseline	*Shared Mooring*		*Shared Mooring and Anchor*	
Mooring Arrangement	Anchor line	Shared line	Anchor line	Shared line	Anchor line
Cost per Line (k$)	118	113	201	113	201
Cost per Anchor (k$)	454	0	624	0	607
Cost per Shared Anchor ($k)	0	0	0	0	819
Installation Cost (k$)	212	0	212	0	212
Decommissioning Cost (k$)	148	0	148	0	148
Number of Moorings (Anchors-Shared Anchors)	30	9	22 (22-0)	9	22 (6-8)
Total Farm Stationkeeping Cost (k$)	**27,950**	**27,090**		**20,670**	

5.3 Levelized Cost of Energy Comparison

Levelized cost of energy (LCOE) is an important metric that is used to compare the cost of various methods of energy generation. As seen in the following equation, the LCOE is levelized annual cost associated with building and operating the asset divided by the annual energy production (AEP) of the asset.

$$LCOE = \frac{(CapEx \times FCR) + OpEx}{(\frac{AEP_{net}}{1000})}$$

There are four categories that factor in to the LCOE calculation: capital expenditures (CapEx), fixed charge rate (FCR), operational expenditures (OpEx), and net annual energy production (AEPnet). The following sections outline each component of the LCOE calculation.

5.3.1 Capital Expenditures

The capital expenditures for an offshore wind project include the turbine cost and the balance of system (BOS) costs. BOS costs include all components other than the turbine itself (i.e. the mooring lines, the electrical system, the substructure, the foundation, etc). The BOS also includes all installation and project development costs. The BOS costs typically account for more than half of the capital expenditures.

NREL's Offshore Renewables Balance of System and Installation Tool (ORBIT) was used to estimate the BOS costs for this project. ORBIT produces component cost estimates such as turbine substructure and offshore substations based on first order models of user inputs. Additionally, ORBIT simulates the installation process of an offshore wind project while accounting for vessel constraints, weather conditions, and resulting delays [19].

ORBIT cost results for a 100-MW wind farm in Humboldt Bay were obtained in a separate NREL analysis. The results are shown in Table 19. Notably, the substructure installation cost is based on a semisubmersible substructure. The installation process for a spar in Humboldt Bay is uncertain due to port and water depth constraints. The semisubmersible installation cost was deemed to be an acceptable substitute for this study, but future work should refine the installation costs to better reflect spar configurations.

Table 19. BOS cost estimates from ORBIT

	ORBIT Cost Estimate ($/kW)
Turbine	1300.00
Substructure	1099.94
Array Cable System	56.02
Export Cable System	403.80
Offshore Substation	270.76
Turbine Installation	432.28
Substructure Installation	167.33
Offshore Substation Installation	45.56
Soft Costs	645.00

Three CapEx components from ORBIT were adjusted for the baseline and shared-mooring designs. The mooring cost was altered based on the calculated line and anchor cost for each design. The mooring installation cost was calculated based on the number of anchors in the array with the assumed installation cost of $212,000 per anchor. The decommissioning cost was calculated based on the number of anchors with the assumed decommissioning cost of $148,000 per anchor. The decommissioning cost was converted to a net present value using a design life of 25 years and a discount rate of 2.72%. The adjusted CapEx costs for the various designs are shown in Table 20.

Table 20. Adjusted cost factors for the baseline and shared-mooring designs

	Baseline	Shared Mooring	Shared Mooring and Anchor
Mooring Cost ($/kW)	171.60	191.72	156.30
Mooring Installation Cost ($/kW)	63.60	46.55	29.63
Decommissioning Cost ($/kW)	22.68	16.65	10.59

Figure 46 shows the estimated capital expenditure per kW of installed capacity for the final designs. The CapEx is very comparable across the designs, with only slight differences. The baseline design has the largest CapEx, followed closely by the shared-mooring design with individual anchors. The shared-mooring shared-anchor design has the lowest CapEx, about 60 $/kW less than the baseline design. The CapEx cost has many components, most of which are the same for the baseline and shared-mooring designs. As a result, the difference in mooring cost has a small effect on the overall capital expenditure.

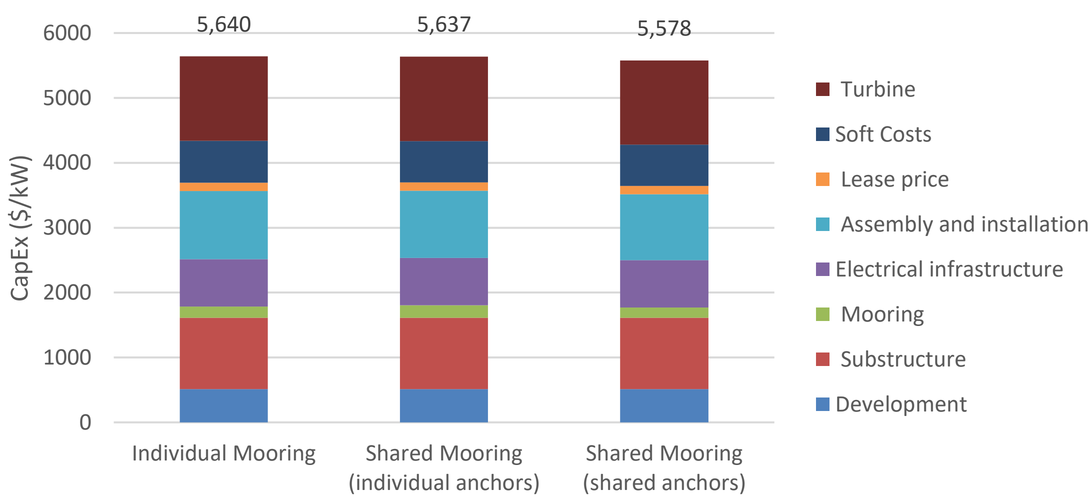


Figure 46. Normalized capital expenditure for the final baseline and shared-mooring designs

5.3.2 Annual Energy Production

Annual Energy Production (AEP) is a key element in the LCOE calculation. The gross AEP is the theoretical energy production without considering losses and it is highly dependent on the wind resource at the site location. In reality, offshore wind turbines do not produce the gross AEP due to losses in power collection and transmission, wake effects, and wind farm availability. The net AEP is the remainder of the gross AEP once losses and availability are accounted for.

NREL's Flow Redirection and Induction in Steady State (FLORIS) software is a wind farm optimization framework with many tools useful for wind farm control and design [36]. The FLORIS Wake Modeling Utility was used to determine wake losses for the chosen farm layout. FLORIS was set up with the chosen farm spacing and DTU 10 MW turbine parameters. The default wake models were used. Figure 47 shows an example of the wake effects on the 10-turbine staircase array. To estimate AEP and wake losses, wind data for Humboldt Bay were obtained from the Wind Integration National Dataset Toolkit which stores meteorological data for many US sites for the years 2007 to 2013. The wind rose for Humboldt Bay is depicted in Figure 48. The wind rose shows that the wind usually comes from the North. FLORIS combines the wind and farm information to generate normalized energy and efficiency plots with respect to wind direction, as shown in Figure 48. The efficiency drops correspond to wind headings where the turbines are aligned in rows, maximizing wake effects. This FLORIS analysis resulted in a wake loss estimation of 1.5%.

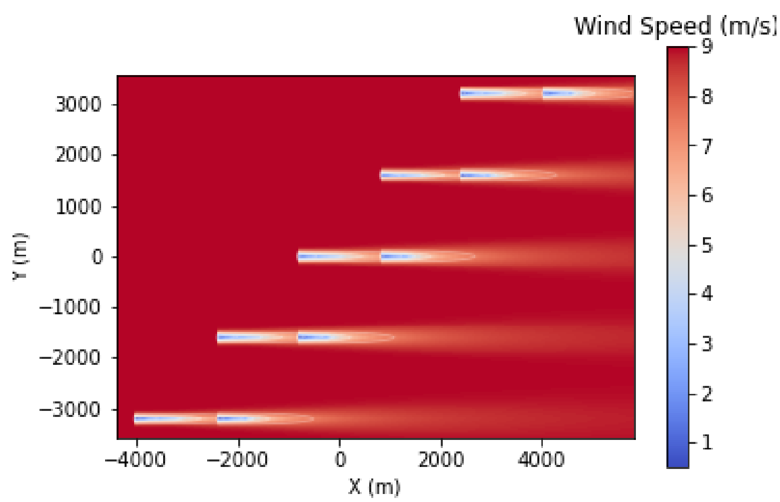
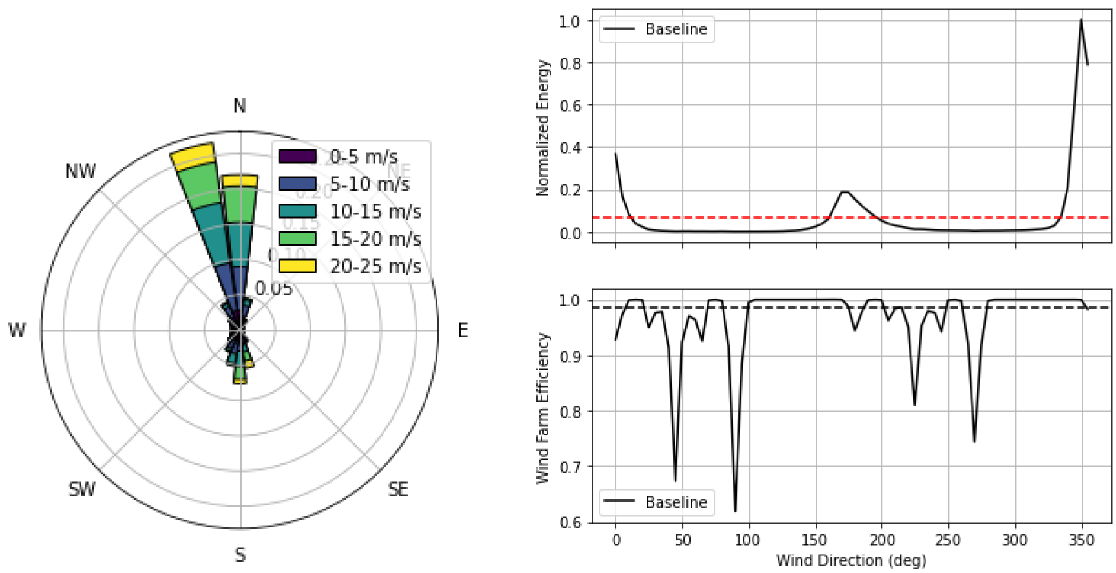


Figure 47. Wake effects for the array at 9 m/s wind speed and 270° wind direction



(a) Wind Rose

(b) Farm energy distribution and efficiency

Figure 48. Humboldt Bay wind rose and farm energy production and efficiency distributions

Additional environmental, technical, electrical, and availability losses were assumed from an existing NREL analysis of floating wind costs for the Humboldt Bay site [37]. The assumed losses for the shared-mooring and baseline designs are documented in Table 21. The losses are combined to obtain a total loss based on the following equation where L_1, L_2 are the individual loss categories:

$$L_{Total} = 1 - (1 - L_1) * (1 - L_2) * \ldots (1 - L_n)$$

The resulting total loss is 12.6% for both designs.

Table 21. AEP Losses

Category	Loss (% gross production)
Wake Losses (from FLORIS)	1.5
Environmental Losses	1.6
Technical Losses	1.2
Electrical Losses	3.9
Availability Losses	5.0
Total Losses	**12.6**

5.3.3 Operational Expenditures

Operational costs are the recurrent costs necessary to maintain a wind farm. Operational costs include insurance, regular maintenance, repair, and additional parts. The cost of maintenance and repairs can vary widely between sites because it depends on the distance to port.

A previous analysis of operational costs for the Humboldt call area using NREL's Offshore Regional Cost Analyzer (ORCA) found annual OpEx costs of $118 per kW of installed capacity. This analysis assumed a semisubmersible substructure and used Humboldt Bay as the O&M port [37].

For this project, the $118/kW annual OpEx is considered a valid assumption for both the shared-mooring and baseline designs. Future work should consider the effect of shared moorings on operational expenditures and refine the cost assumptions to better represent a spar substructure.

5.3.4 Financing

Project financing is characterized in the LCOE calculation by the fixed charge rate (FCR). The fixed charge rate is the percentage of total plant cost required to pay annual carrying charges. The FCR is based on the capital recovery factor as well as depreciation and corporate income taxes.

NREL's *2019 Cost of Wind Energy Review* outlines the LCOE calculation for an offshore wind reference project [38]. This report assumes a project life of 25 years and that 100% of the project cost is eligible for a 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation. The discount rate was calculated using assumptions from NREL's 2019 Annual Technology Baseline and resulted in a nominal and real weighted average cost of capital (WACC) of 5.29% and 2.72% respectively. Based on the assumed project life, depreciation, and discount rate, the nominal and real FCR are 7.64% and 5.82%. Table 22 summarizes the economic metrics from [38] that were adopted for the LCOE calculations in this project.

Table 22. Summary of economic evaluation metrics

Metric	Nominal	Real
Weighted average cost of capital	5.29%	2.72%
Capital recovery factor	7.30%	5.60%
Fixed charge rate	7.64%	5.82%

5.3.5 LCOE Comparison

The CapEx, OpEx, AEP, and FCR calculations and assumptions were combined to produce a final LCOE estimation. Table 23 shows the LCOE for the baseline and shared-mooring designs. The baseline design has the largest LCOE at $119.41/MWh. The shared-mooring design with individual anchors is only 0.04% less than the baseline. The shared-mooring design with shared anchors shows a more noticeable LCOE reduction of 0.85% compared to the baseline. This ~1% LCOE reduction is not insignificant in the context of large-scale projects.

The LCOE results were highly influenced by the assumptions in the CapEx, OpEx, AEP, and FCR, as well as the cost assumptions for the mooring systems. Many of the LCOE costs were assumed to be the same for the baseline and shared-mooring designs. The mooring cost differences became less significant when weighed with the many other cost inputs into the LCOE. Future studies should review these assumptions and more closely evaluate the LCOE inputs for a shared-mooring farm, especially installation and operating costs.

Table 23. Levelized cost of energy for final designs

Design	LCOE ($/MWh)	Percent Difference from Baseline
Baseline	119.41	-
Shared Moorings	119.36	-0.04%
Shared Moorings with Shared Anchors	118.39	-0.85%

5.4 Adjusted Cost Comparison Considering Redundancy

The previous section discussed the considerable advantages of the shared-mooring system in failure scenarios when compared to the three-line baseline design. The maximum offsets in line failures for the shared-mooring design are less than half of the baseline design's offsets, due to the more redundant nature of the shared-mooring design. This significant difference in offsets could allow the shared-mooring design to be considered a redundant mooring system, depending on other system constraints. If this behavior was desired in an array to mitigate risks from line failures, it would suggest that the baseline design should also have these redundancy characteristics. This could be achieved using a baseline mooring design with four lines instead of three.

To allow a cost comparison with more equivalent redundancy characteristics between the shared-mooring and baseline designs, the cost for a four-line baseline design was calculated and compared to the shared-mooring design. The four-line baseline design was estimated by comparing quasi-static surge offsets for the three-line baseline design and a four-line design with the same line properties. The ratio of surge offsets for the four-line system divided by the three-line system was found to be approximately 0.75. This ratio was applied to the line cross-sectional area of the three-line design to lighten the line diameters and reduce per-line costs. Similarly, the 0.75 ratio was applied to the anchor capacity of the original three-line baseline. The overall four-line design cost was estimated using the adjusted line and anchor costs applied to a four-line system. The 0.75 ratio was based on a linear analysis and is likely to be an underestimate of the necessary line diameters and anchor capacity required for non-linear dynamic situations. Therefore, the estimated four-line baseline design cost is likely to be an underestimate, making the shared-mooring designs' cost-reduction estimates conservative.

Table 24 shows the cost comparison of the three- and four-line baseline designs compared to the shared-mooring designs. The shared-mooring design reduces the stationkeeping cost by 13% compared to the four-line baseline. With the addition of shared anchors, the cost is reduced by 34%. This calculation shows that the shared-mooring design has significant cost savings over an equally redundant baseline design with four lines. Future work should refine the four-line baseline design with the same iteration process used to adjust the shared-mooring and three-line baseline designs.

Table 24. Stationkeeping cost comparison with equivalent four-line baseline design

Design	Total Farm Stationkeeping Cost (k$)	Percent Difference from Three-Line Baseline	Percent Difference from Four Line Baseline
Three-Line Baseline	27,950	-	-
Modified Four-Line Baseline	31,120	11.36%	-
Shared Mooring	27,090	-3.08%	-12.97%
Shared Mooring and Anchor	20,670	-26.06%	-33.60%

5.5 Conclusions

To extend the loads analysis, the tower-base bending moment load statics and mooring line damage equivalent loads were also compared. The tower-base bending moment statistics are not significantly different between the baseline and shared-mooring designs, showing that the shared mooring arrangement does not introduce additional tower loads. The damage equivalent loads of the mooring system were evaluated at the anchor and turbine connection points for directly upwind and downwind lines. The damage equivalent loads are generally lower for the shared-mooring design in the normal condition. The damage in the 50-year condition is considerably higher for the shared-mooring design than for the baseline design but, with the cumulative nature of fatigue and the infrequency of this condition, the shared-mooring approach is concluded to not increase overall fatigue loads. In sum, the shared-mooring design is not seen to negatively impact mooring fatigue loads or wind turbine structural loads.

A levelized cost of energy calculation was carried out for the baseline and shared-mooring designs using NREL's tools and resources. The capital expenditure was determined using ORBIT results for balance of system costs with adjustments for the shared-mooring and baseline designs. The annual energy production for the wind farm was estimated in FLORIS, with wind rose data for Humboldt Bay. The operational costs and fixed charge rate were taken from previous NREL studies. The resulting LCOE estimates are very comparable between the baseline and shared-mooring designs. The shared-mooring with shared-anchor option shows the most significant cost reduction, at 0.85% less than the original baseline. The LCOE estimation showed that shared-mooring systems have the potential to modestly improve overall cost metrics when weighed against the many other components of the LCOE. To more accurately quantify LCOE savings, future studies should evaluate the installation and maintenance cost differences between the baseline and shared-mooring designs.

In the case of a mooring line failure, the shared-mooring designs have significantly smaller offsets than the original baseline design, making it more likely to satisfy redundancy criteria. To quantify the cost difference if the baseline design had the same characteristics, a variation of the baseline design with four mooring lines was estimated. Using this variation as the baseline increases the potential stationkeeping cost savings of the shared-mooring design from 26% to 34%.

6 Project Conclusions

This project explored the feasibility of using shared mooring lines to lower the cost of floating wind farms in deep water. It approached this by developing a first-of-its-kind conceptual floating wind array design featuring a shared mooring system and then comparing it against a conventional individually moored floating wind array design under identical conditions. The array size was 100 MW, with ten 10-MW turbines on spar floating platforms, and the site conditions were taken to be representative of the Humboldt lease area off the Northern coast of California, with a simplified water depth of 600 m. The project developed and optimized a shared-mooring floating wind turbine array design, improved modeling tools to support such a design, and then performed an analysis comparing the novel design to a baseline array featuring individual mooring lines. This comparison demonstrated notable cost advantages to sharing stationkeeping system components. In the course of this work, the project also developed new methods for designing and analyzing shared mooring systems in general. The overall conclusions of the project are listed below.

Methodological conclusions:

- A linearized analysis method can drastically simplify the layout and conceptual design process for shared mooring systems.
- Individual mooring line optimization using quasi-static models can produce cost-optimized mooring line designs that approximately satisfy relevant technical constraints.
- Coupling the individual mooring line optimization and array-level linearized optimization methods provides a systematic solution for optimizing a shared-mooring floating wind array design.
- Upgrades to the FAST.Farm model allow accurate coupled dynamics modeling of floating wind farms with shared mooring lines.
- Checking constraints from dynamic simulations and revising quasi-static assumptions gives a successful method for complete design of a shared-mooring floating wind farm to meet design constraints and stipulations from existing standards.

Design and performance conclusions:

- Shared mooring systems have ideal and evenly distributed stationkeeping properties when perpendicular anchor line pairs are used for each turbine.
- Inline series of shared mooring lines can create unfavorable array-wide couplings that degrade stationkeeping system performance.
- The selected staggered shared-mooring design with perpendicular anchor line pairs and alternating shared line directions has excellent dynamic performance with uniform stationkeeping and minimal intra-array couplings.

- The selected shared-mooring design has significantly smaller excursions following a line failure than a conventional 3-line mooring system.
- The selected shared-mooring array design did not show any problematic behaviors or resonant motions across the range of design-driving load cases.
- In the conditions studied, the use of shared mooring lines can reduce mooring system installed cost by 3% relative to a 3-line conventional design, and by 13% relative to a 4-line conventional design.
- In the conditions studied, the use of shared mooring lines combined with shared anchors can reduce mooring system installed cost by 26% relative to a 3-line conventional design, and by 34% relative to a 4-line conventional design.
- The above mooring system cost reductions result in an LCOE reduction on the order of 1%, which is not negligible on the scale of a large offshore wind project. Furthermore, additional non-monetary benefits exist related to reduced seabed disturbance and greater redundancy.

The project shed light on the design of shared mooring systems and provided an early demonstration of how shared stationkeeping components can reduce overall stationkeeping system material and installation costs, thereby lowering the LCOE of wind farms in deep waters. These research efforts provide a new level of detail in analyzing shared mooring systems at the scale of up to 10 turbines. Future work could explore alternate designs or larger scales where additional shared-mooring techniques become necessary, as well as the broader implications related to installation processes, fishing and navigation restrictions, and other practical deployment considerations.

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[38] T. Stehly, P. Beiter, and P. Duffy, "2019 Cost of Wind Energy Review," National Renewable Energy Lab. (NREL), Golden, CO (United States), NREL/TP-5000-78471, Dec. 2020. doi: 10.2172/1756710.
[39] "66 kV Submarine Cable Systems for Offshore Wind," Prysmian Group. Accessed: Jun. 18, 2021. [Online]. Available: www.prysmiangroup.com/en/en_hv-and-submarine_submarine-energy-systems_mv-submarine_submarine-energy-systems.html

Appendix A. OpenFAST and FAST.Farm Model Setup

From the design information defined in Deliverables 1.1 and 1.2, OpenFAST models of the baseline individually moored design and the conceptual shared-mooring array design were created. These models were run through a number of checks to verify the modeling approach and the design parameters.

A.1. Baseline Design Setup in OpenFAST

The baseline design as described in Sections 1 and 2 was set up in OpenFAST, including input files for modeling of the floating spar platform (in HydroDyn), the individual 3-line bridle mooring system (in MoorDyn), and the DTU 10 MW turbine (in ElastoDyn, AeroDyn, ServoDyn, etc.). The OpenFAST primary file, HydroDyn file, and MoorDyn file were set up based on the information presented in Sections 1 and 2. The many turbine-related input files were adapted from already-published input files for the DTU 10 MW turbine design [12].

The following subsections describe the series of checks that were applied to the improved baseline design OpenFAST model. Some checks involve a comparison to the quasi-static analysis that was performed in Section 2.

A.1.1. Unloaded Equilibrium Check

The first evaluation of the design is to determine the structure's equilibrium position. This is measured by comparing the mass and displacement of the structure under calm conditions (no wind and no waves). Using the optimized mooring system, the original baseline design was found to undervalue the total platform mass, resulting in a heave offset of 6-7 meters upwards. The platform ballast was augmented by 260 tonnes to account for this heave offset, resulting in a total platform mass of 12,770 tonnes and a zero-meter heave offset.

The mooring line tensions under the unloaded condition are also of interest. The baseline design has three moorings each tied to an anchor. Each mooring has three mooring lines, the main one that connects the anchor to the bridle point, and the two smaller lines that connect the bridle point to the fairleads. The equilibrium tensions for each mooring line were calculated from the unloaded OpenFAST simulation, as well as the quasi-static MoorPy analysis, and tabulated in Table 19.

Table 25: Mooring line tensions in OpenFAST and MoorPy in unloaded condition

	OpenFAST Tension (N)	MoorPy tension (N)
Main 1	1,092,232	1,093,792
Bridle-R 1	554,629	554,667
Bridle-L 1	552,088	553,078
Main 2	1,092,194	1,093,779
Bridle-R 2	551,886	552,125
Bridle-L 2	554,781	555,308
Main 3	1,092,163	1,093,764
Bridle-R 3	553,486	554,646
Bridle-L 3	553,146	553,065

As seen from the table, the average tensions calculated from OpenFAST and the quasi-static tensions from MoorPy are very similar to each other, since there are no dynamics involved in an unloaded simulation, which further validates our steady-state quasi-static analysis tool MoorPy.

A.1.2. Mean Offsets Check

The mean offsets check is similar to the unloaded equilibrium check, except the model is now exposed to the rated wind speed, which produces a wind thrust force of 1.5 MN. This wind thrust force is applied to the OpenFAST model, as well as the quasi-static MoorPy model. Table 26 shows the mean offsets of the model at the end of the design simulation, as well as the offsets measured in MoorPy.

Table 26. Mean offsets for 6DOF under rated wind in OpenFAST and MoorPy

Offset	Surge (m)	Sway (m)	Heave (m)	Roll (deg)	Pitch (deg)	Yaw (deg)
OpenFAST	57.54	-0.82	-0.55	0.19	3.38	0.41
MoorPy	59.62	-1.42	-0.10	0.009	5.81	0.016

In the OpenFAST simulation, the platform settles at an average surge offset of 57.54 meters and in the quasi-static analysis, the platform settles at a surge offset of 59.62 meters, both of which are less than the prescribed maximum surge offset of 60 meters. The reduced offset in the OpenFAST simulation is expected because the platform pitch results in a small reduction in the turbine thrust force.

The mooring line tensions are again of interest in the rated wind condition. An average value of the mooring line tensions was taken for the second half of the OpenFAST simulation to allow the system to reach steady state. These tensions are compared to the mooring line tensions calculated in MoorPy in Section 2.

Table 27. Mooring line tensions in OpenFAST and MoorPy under rated wind

	OpenFAST Tension (N)	MoorPy tension (N)
Main 1	294,027	286,560
Bridle-R 1	158,592	139,686
Bridle-L 1	142,557	152,796
Main 2	1,122,266	1,140,425
Bridle-R 2	560,611	589,700
Bridle-L 2	576,440	564,794
Main 3	2,026,558	2,046,517
Bridle-R 3	1,056,162	1,026,446
Bridle-L 3	993,830	1,042,866

A.1.3. Natural Frequency Check

The method used to calculate and check the natural frequencies of a model is to run decay tests. Each degree of freedom was set to an initial position and then released, allowing the model to oscillate from that initial position under an unloaded condition. The frequency of oscillation from that initial position is the natural frequency of that degree of freedom.

Six simulations were run for the six degrees of freedom with no wind and no waves. The oscillation frequencies of each degree of freedom were calculated by finding the peak frequency of the time series. Figure 49 shows the decay test time series of each DOF and Table 28 shows the resulting natural frequencies and natural periods.

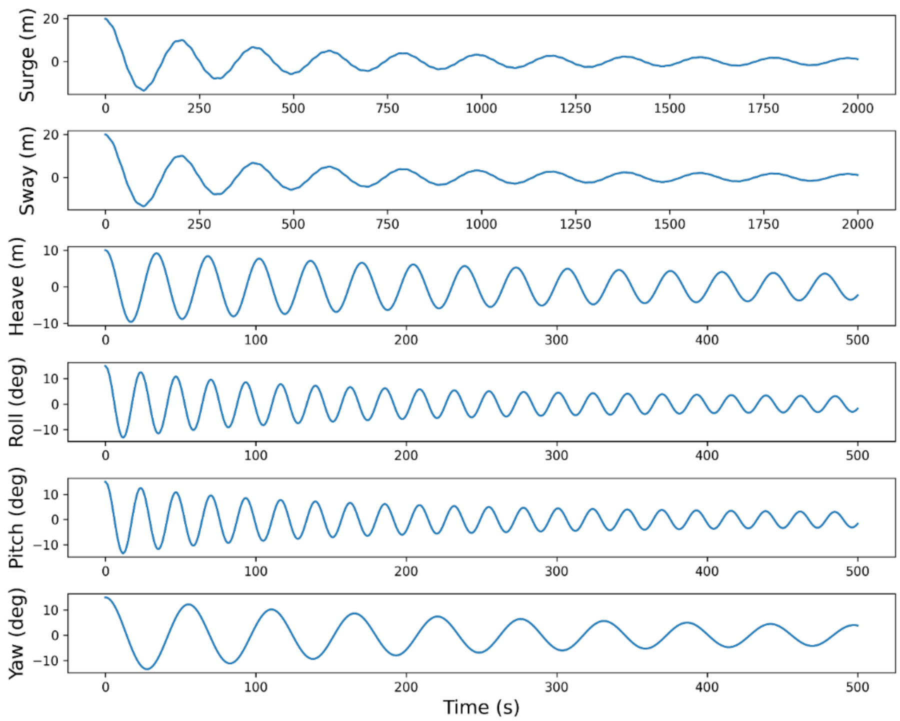

Figure 49. Decay test in six degrees of freedom

Table 28. Natural Frequencies and periods from decay tests

Degree of Freedom	Natural Frequency (Hz)	Natural Period (s)
Surge	0.005	200.0
Sway	0.005	200.0
Heave	0.028	35.7
Roll	0.044	22.7
Pitch	0.044	22.7
Yaw	0.018	55.6

These results are reasonable natural frequencies for a spar platform, which further verifies the OpenFAST model of the baseline design.

A.1.4. Dynamic Response Check

The baseline design was simulated in OpenFAST under several wind and wave conditions to check for reasonable behavior.

It was run with steady wind and a white noise wave excitation spectrum to check its RAOs. The RAOs for each DOF were calculated using each DOF's time series power spectral density curves. The RAO peaks for each DOF align well with the natural frequencies as outlined in Table 11 and none of them are too large of magnitude within the wave frequency range of 0.5 Hz.

It was also run under turbulent wind and severe JONSWAP waves to check its response under realistic conditions, considering platform motions, turbine tower-base loads, and mooring tensions. During the turbulent wind and irregular waves, the platform did not exceed any extreme value in any degree of freedom, meaning that it is well suited for the rated environment. The main mooring line tensions show reasonable results and have maximum values that are only 20-30% of the line's minimum breaking load (MBL). Lastly, the overturning moment at the tower base follows the pitch response relatively closely, indicating that no large unexpected structural responses are occurring.

A.2. Dynamic Power Cable Design

Coupled dynamics simulations of the full system in OpenFAST for this project were initially intended to include the dynamic intra-array power cables. Basic properties of a suitable dynamic power cable were selected for this purpose. It is a 66 kV power cable, consistent with the power cables currently used on similarly-sized floating wind farms such as Hywind Tampen. Referring to published product information about 66 kV cables for offshore wind [39], the assumed cross-sectional properties include a diameter of 175 mm and a weight of 39.4 kg/m. The dynamic cable configuration, including a buoyancy section to produce a lazy wave profile, was designed to support the 60 m offset range of the mooring system designs and to work for both the baseline and shared-mooring arrays. The resulting dynamic cable design parameters are listed in Table 29.

Table 29. Dynamic power cable design parameters

Parameter	Top section	Buoyancy section	Bottom section
Diameter (mm)	175	175	175
Mass (kg/m)	40	40	40
Additional buoyancy (kg/m)	-	30	-
Volume-equivalent diameter (mm)	175	260	175
Length (m)	280	300	600

The dynamic cable profile is shown in Figure 50, with the buoyancy section drawn in red and the cable profile at extreme 60 m offsets drawn in grey. The moderate curvatures and minimal change in seabed contact across the displacement range indicate that this design performs well from a quasi-static point of view. This dynamic cable profile will be used to connect each adjacent turbine pair in the array, running beneath the shared mooring lines. A visualization of the shared-mooring array with the dynamic cables included is shown in Figure 51.

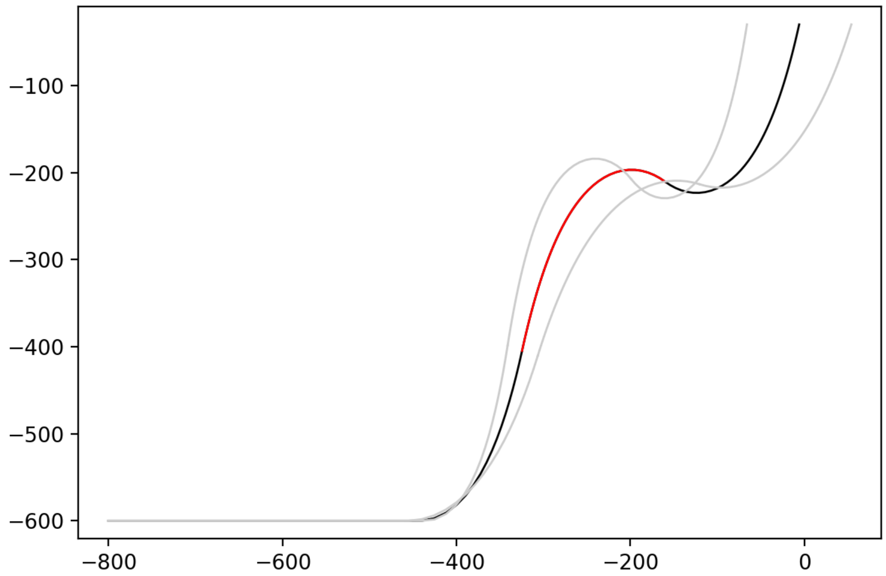

Figure 50. Dynamic cable profile with buoyancy section (red) and +/- 60 m offset profiles (grey)

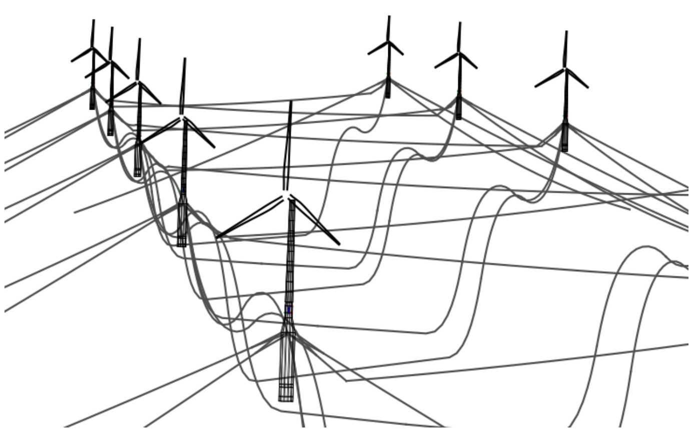

Figure 51. Array illustration showing dynamic power cables underneath shared lines

A.3. Shared-Mooring Array Design Setup in FAST.Farm

Initial checks of the shared-mooring design in FAST.Farm were shown in the main body of the report in Section 4.2.2. However, the setup of FAST.Farm model for shared mooring lines is unique to this project, so more detail about the setup is provided here.

Set up of the shared-mooring FAST.Farm simulation involved three main points of novelty: dealing with nonzero wind-wave headings, setting up the FAST.Farm primary input file, and setting up the array-level MoorDyn input file. These are discussed in the following subsections.

A.3.1. Handling Nonzero Wind-Wave Headings

FAST.Farm was not set up to support nonzero wind headings. To account for this, the entire shared-mooring farm was rotated while keeping a zero wind heading to simulate the -45° to 45° wind headings. This process is more involved for a floating wind farm because it requires that the turbine locations, anchor positions, and other mooring connection positions all be rotated as well. Scripts were added to the mooring design tools used in Section 2 to facilitate automatic rotation of these components in the input files.

A.3.2. FAST.Farm Primary Input File

The FAST.Farm primary input file specifies the turbine initial positions for the array and also specifies settings for the new modeling options discussed in Section 3. A version of this input file that was used to first test the full shared-mooring floating array in FAST.Farm is provided below:

```
FAST.Farm v1.00.* INPUT FILE
Shared Moorings Project -  DTU 10MW Turbine - Hywind-like Spar - Staircase Array - n=10
--- SIMULATION CONTROL ---
False              Echo               Echo input data to <RootName>.ech? (flag)
"FATAL"            AbortLevel         Error level when simulation should abort (string) {"WARNING", "SEVERE
400.0              TMax               Total run time (s) [>=0.0]
False              UseSC              Use a super controller? (flag)
2                  Mod_AmbWind        Ambient wind model (-) (switch) {1: high-fidelity precursor in VTK form
1                  Mod_WaveField      Wave field handling (-) (switch) {1: use individual HydroDyn inputs wit
3                  Mod_SharedMooring  Shared mooring system model (switch) {0: None, 3=MoorDyn}
--- SUPER CONTROLLER --- [used only for UseSC=True]
"SC_DLL.dll"       SC_FileName        Name/location of the dynamic library {.dll [Windows] or .so [Linux]} co
--- SHARED MOORING SYSTEM --- [used only for Mod_SharedMoor>0]
"FarmMoorDyn_design.dat"  SharedMoorFile     Name of file containing shared mooring system input parameters (
0.025              DT_Mooring         Time step for farm-level mooring coupling with each turbine (s) [used o
--- AMBIENT WIND ---
3.0                DT                 Time step for low -resolution wind data input files; will be used as th
0.1                DT_High            Time step for high-resolution wind data input files (s) [>0.0]
"Unused"           WindFilePath       Path name to wind data files from precursor (string)
False              ChkWndFiles        Check all the ambient wind files for data consistency? (flag)
--- AMBIENT WIND: INFLOWWIND MODULE --- [used only for Mod_AmbWind=2]
3.0                DT                 Time step for low -resolution wind data interpolation; will be used as
```

```
0.1                DT_High            Time step for high-resolution wind data interpolation (s) [>0.0]
881                NX_Low             Number  of low -resolution spatial nodes in X direction for wind data i
24                 NY_Low             Number  of low -resolution spatial nodes in Y direction for wind data in
24                 NZ_Low             Number  of low -resolution spatial nodes in Z direction for wind data in
-4400.0            X0_Low             Origin  of low -resolution spatial nodes in X direction for wind data i
-115.0             Y0_Low             Origin  of low -resolution spatial nodes in Y direction for wind data in
4.0                Z0_Low             Origin  of low -resolution spatial nodes in Z direction for wind data i
10.0               dX_Low             Spacing of low -resolution spatial nodes in X direction for wind data i
10.0               dY_Low             Spacing of low -resolution spatial nodes in Y direction for wind data i
10.0               dZ_Low             Spacing of low -resolution spatial nodes in Z direction for wind data i
81                 NX_High            Number  of high-resolution spatial nodes in X direction for wind data i
81                 NY_High            Number  of high-resolution spatial nodes in Y direction for wind data i
20                 NZ_High            Number  of high-resolution spatial nodes in Z direction for wind data in
"InflowWind.dat"   InflowFile         Name of file containing InflowWind module input parameters (quoted stri
--- WIND TURBINES ---
10                  NumTurbines        Number of wind turbines (-) [>=1]                          [last 6 col
WT_X      WT_Y     WT_Z   WT_FASTInFile                     X0_High  Y0_High  Z0_High  dX_High  dY_High  dZ_Hi
(m)       (m)      (m)    (string)                           (m)      (m)      (m)      (m)      (m)      (m)
-4000.0  -3200.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT1.fst"  -4400.0  -3600.0    4.0      10.0     10.0     10.0
-2400.0  -3200.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT2.fst"  -2800.0  -3600.0    4.0      10.0     10.0     10.0
-2400.0  -1600.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT3.fst"  -2800.0  -2000.0    4.0      10.0     10.0     10.0
 -800.0  -1600.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT4.fst"  -1200.0  -2000.0    4.0      10.0     10.0     10.0
 -800.0      0.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT5.fst"  -1200.0   -400.0    4.0      10.0     10.0     10.0
  800.0      0.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT6.fst"    400.0   -400.0    4.0      10.0     10.0     10.0
  800.0   1600.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT7.fst"    400.0   1200.0    4.0      10.0     10.0     10.0
 2400.0   1600.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT8.fst"   2000.0   1200.0    4.0      10.0     10.0     10.0
 2400.0   3200.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT9.fst"   2000.0   2800.0    4.0      10.0     10.0     10.0
 4000.0   3200.0  0.0    "DTU_10MW_NAUTILUS_GoM_WT10.fst"  3600.0   2800.0    4.0      10.0     10.0     10.0
--- WAKE DYNAMICS ---
5.0                dr                 Radial increment of radial finite-difference grid (m) [>0.0]
55                 NumRadii           Number of radii in the radial finite-difference grid (-) [>=2]
136                NumPlanes          Number of wake planes (-) [>=2]
DEFAULT            f_c                Cut-off (corner) frequency of the low-pass time-filter for the wake adv
DEFAULT            C_HWkDfl_O         Calibrated parameter in the correction for wake deflection defining the
DEFAULT            C_HWkDfl_OY        Calibrated parameter in the correction for wake deflection defining the
DEFAULT            C_HWkDfl_x         Calibrated parameter in the correction for wake deflection defining the
DEFAULT            C_HWkDfl_xY        Calibrated parameter in the correction for wake deflection defining the
DEFAULT            C_NearWake         Calibrated parameter for the near-wake correction (-) [>1.0] or DEFAULT
DEFAULT            k_vAmb             Calibrated parameter for the influence of ambient turbulence in the edd
DEFAULT            k_vShr             Calibrated parameter for the influence of the shear layer    in the edd
DEFAULT            C_vAmb_DMin        Calibrated parameter in the eddy viscosity filter function for ambient
DEFAULT            C_vAmb_DMax        Calibrated parameter in the eddy viscosity filter function for ambient
DEFAULT            C_vAmb_FMin        Calibrated parameter in the eddy viscosity filter function for ambient
DEFAULT            C_vAmb_Exp         Calibrated parameter in the eddy viscosity filter function for ambient
DEFAULT            C_vShr_DMin        Calibrated parameter in the eddy viscosity filter function for the shea
DEFAULT            C_vShr_DMax        Calibrated parameter in the eddy viscosity filter function for the shea
DEFAULT            C_vShr_FMin        Calibrated parameter in the eddy viscosity filter function for the shea
DEFAULT            C_vShr_Exp         Calibrated parameter in the eddy viscosity filter function for the shea
DEFAULT            Mod_WakeDiam       Wake diameter calculation model (-) (switch) {1: rotor diameter, 2: vel
DEFAULT            C_WakeDiam         Calibrated parameter for wake diameter calculation (-) [>0.0 and <0.99]
DEFAULT            Mod_Meander        Spatial filter model for wake meandering (-) (switch) {1: uniform, 2: t
DEFAULT            C_Meander          Calibrated parameter for wake meandering (-) [>=1.0] or DEFAULT [DEFAUL
--- VISUALIZATION ---
False              WrDisWind          Write low- and high-resolution disturbed wind data to <RootName>.Low.Di
0                  NOutDisWindXY      Number of XY planes for output of disturbed wind data across the low-re
85.0               OutDisWindZ        Z coordinates of XY planes for output of disturbed wind data across the
0                  NOutDisWindYZ      Number of YZ planes for output of disturbed wind data across the low-re
748.0, 1252.0, 1378.0, 1504.0, 1630.0, 1756.0, 1882.0, 2008.0   OutDisWindX        X coordinates of YZ planes
0                  NOutDisWindXZ      Number of XZ planes for output of disturbed wind data across the low-re
0.0             OutDisWindY        Y coordinates of XZ planes for output of disturbed wind data across the lo
3.0                WrDisDT            Time step for disturbed wind visualization output (s) [>0.0] or DEFAULT
--- OUTPUT ---
True               SumPrint           Print summary data to <RootName>.sum? (flag)
99999.9            ChkptTime          Amount of time between creating checkpoint files for potential restart
0.0                TStart             Time to begin tabular output (s) [>=0.0]
1                  OutFileFmt         Format for tabular (time-marching) output file (switch) {1: text file [
True               TabDelim           Use tab delimiters in text tabular output file? (flag) {uses spaces if
"ES10.3E2"         OutFmt             Format used for text tabular output, excluding the time channel.  Resul
20                 NOutRadii          Number of radial nodes         for wake output for an individual rotor
```

```
0, 1, 2, 3, 4, 5, 7, 9, 11, 13, 15, 16, 17, 18, 19, 21, 24, 28, 33, 39  OutRadii           List of radial nod
7                  NOutDist           Number of downstream distances for wake output for an individual rotor
252.0, 378.0, 504.0, 630.0, 756.0, 882.0, 1008.0          OutDist            List of downstream distances for
1                  NWindVel           Number of points for wind output (-) [0 to 9]
1000.0             WindVelX           List of coordinates in the X direction for wind output (m) [1 to NWindV
0.0             WindVelY           List of coordinates in the Y direction for wind output (m) [1 to NWindVel]
90.0               WindVelZ           List of coordinates in the Z direction for wind output (m) [1 to NWindV
                   OutList            The next line(s) contains a list of output parameters.  See OutListPara
"RtAxsXT1     , RtAxsYT1     , RtAxsZT1"
END of input file (the word "END" must appear in the first 3 columns of this last OutList line)
```

A.3.3. MoorDyn Input File

The MoorDyn input file for the shared mooring system is unprecedented in that it contains all the mooring lines for 10 interconnected floating wind turbines. This amounts to a total of 183 mooring line and cable segments when the intra-array power cables are also included. A version of this input file that was used to first test the full shared-mooring floating array in FAST.Farm is provided below:

```
---------------- MoorDyn FAST.Farm Input File ------------------
Generated by MoorDesign
FALSE    Echo      - echo the input file data (flag)
---------------------- LINE TYPES -----------------------------------------------------
5    NTypes   - number of LineTypes
LineType         Diam     MassDen   EA        BA/-zeta     Can    Cat    Cdn    Cdt
   (-)           (m)      (kg/m)    (N)       (N-s/-)      (-)    (-)    (-)    (-)
segment1         0.1710   31.548  43103017.5 -1.0    0.8     0.25    2.0     0.40
segment2         0.1710   31.548  43103017.5 -1.0    0.8     0.25    2.0     0.40
polyester213     0.1832   36.203  49461981.8 -1.0    0.8     0.25    2.0     0.40
cable            0.1750   40.000 751000000.0 -1.0    0.8     0.25    2.0     0.40
buoyancy         0.2600   40.000 751000000.0 -1.0    0.8     0.25    2.0     0.40
---------------------- CONNECTION PROPERTIES -----------------------------------------------------
232    NConnects   - number of connections including anchors and fairleads
Node    Type          X         Y         Z        M      V      FX     FY     FZ    CdA    Ca
(-)     (-)          (m)       (m)       (m)      (kg)   (m^3)  (kN)   (kN)   (kN)  (m^2)   ()
1    Turbine2        -5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
2    Turbine2        -5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
3    Connect      -2440.00 -3200.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
4    Connect      -2493.33 -3200.00    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
5    Connect      -3906.67 -3200.00    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
6    Turbine1         5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
7    Turbine1         5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
8    Connect      -3960.00 -3200.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
9    Turbine3         5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
10   Turbine3        -5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
11   Connect      -2400.00 -1640.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
12   Connect      -2400.00 -1693.33    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
13   Connect      -2400.00 -3106.67    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
14   Turbine2        -5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
15   Turbine2         5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
16   Connect      -2400.00 -3160.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
17   Turbine4        -5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
18   Turbine4        -5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
19   Connect       -840.00 -1600.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
20   Connect       -893.33 -1600.00    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
21   Connect      -2306.67 -1600.00    -77.56 99088.06   0.00   0.00   0.00   0.00   0.00   0.00
22   Turbine3         5.57      5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
23   Turbine3         5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
24   Connect      -2360.00 -1600.00    -50.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
25   Turbine5         5.57     -5.57    -21.00     0.00   0.00   0.00   0.00   0.00   0.00   0.00
```

26	Turbine5	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Connect	-800.00	-40.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Connect	-800.00	-93.33	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
29	Connect	-800.00	-1506.67	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
30	Turbine4	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Turbine4	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Connect	-800.00	-1560.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Turbine6	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	Turbine6	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Connect	760.00	0.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	Connect	706.67	0.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
37	Connect	-706.67	0.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
38	Turbine5	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39	Turbine5	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	Connect	-760.00	0.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	Turbine7	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	Turbine7	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	Connect	800.00	1560.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	Connect	800.00	1506.67	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
45	Connect	800.00	93.33	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
46	Turbine6	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	Turbine6	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
48	Connect	800.00	40.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
49	Turbine8	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50	Turbine8	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
51	Connect	2360.00	1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	Connect	2306.67	1600.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
53	Connect	893.33	1600.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
54	Turbine7	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	Turbine7	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Connect	840.00	1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Turbine9	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Turbine9	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	Connect	2400.00	3160.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Connect	2400.00	3106.67	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
61	Connect	2400.00	1693.33	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
62	Turbine8	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
63	Turbine8	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
64	Connect	2400.00	1640.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65	Turbine10	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
66	Turbine10	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
67	Connect	3960.00	3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
68	Connect	3906.67	3200.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
69	Connect	2493.33	3200.00	-77.56	99088.06	0.00	0.00	0.00	0.00	0.00	0.00
70	Turbine9	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
71	Turbine9	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
72	Connect	2440.00	3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
73	Fixed	-4000.00	-4800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
74	Turbine1	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
75	Turbine1	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
76	Connect	-4000.00	-3240.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
77	Fixed	-5600.00	-3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
78	Turbine1	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
79	Turbine1	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
80	Connect	-4040.00	-3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
81	Fixed	-4000.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
82	Turbine1	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
83	Turbine1	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
84	Connect	-4000.00	-3160.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
85	Fixed	-2400.00	-4800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86	Turbine2	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
87	Turbine2	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
88	Connect	-2400.00	-3240.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
89	Fixed	-800.00	-3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
90	Turbine2	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
91	Turbine2	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
92	Connect	-2360.00	-3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
93	Fixed	-4000.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
94	Turbine3	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

95	Turbine3	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
96	Connect	-2440.00	-1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
97	Fixed	-2400.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
98	Turbine3	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
99	Turbine3	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
100	Connect	-2400.00	-1560.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
101	Fixed	-800.00	-3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
102	Turbine4	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
103	Turbine4	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
104	Connect	-800.00	-1640.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
105	Fixed	800.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
106	Turbine4	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
107	Turbine4	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
108	Connect	-760.00	-1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
109	Fixed	-2400.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
110	Turbine5	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
111	Turbine5	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
112	Connect	-840.00	0.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
113	Fixed	-800.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
114	Turbine5	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
115	Turbine5	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
116	Connect	-800.00	40.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
117	Fixed	800.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
118	Turbine6	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
119	Turbine6	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
120	Connect	800.00	-40.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
121	Fixed	2400.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
122	Turbine6	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
123	Turbine6	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
124	Connect	840.00	0.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
125	Fixed	-800.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
126	Turbine7	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
127	Turbine7	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
128	Connect	760.00	1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
129	Fixed	800.00	3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
130	Turbine7	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
131	Turbine7	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
132	Connect	800.00	1640.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
133	Fixed	2400.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
134	Turbine8	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
135	Turbine8	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
136	Connect	2400.00	1560.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
137	Fixed	4000.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
138	Turbine8	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
139	Turbine8	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
140	Connect	2440.00	1600.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
141	Fixed	800.00	3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
142	Turbine9	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
143	Turbine9	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
144	Connect	2360.00	3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
145	Fixed	2400.00	4800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
146	Turbine9	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
147	Turbine9	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
148	Connect	2400.00	3240.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
149	Fixed	4000.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
150	Turbine10	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
151	Turbine10	-5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
152	Connect	4000.00	3160.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
153	Fixed	5600.00	3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
154	Turbine10	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
155	Turbine10	5.57	-5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
156	Connect	4040.00	3200.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
157	Fixed	4000.00	4800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
158	Turbine10	-5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
159	Turbine10	5.57	5.57	-21.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
160	Connect	4000.00	3240.00	-50.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
161	Fixed	-3200.00	-3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
162	Connect	-3675.49	-3200.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
163	Connect	-3839.91	-3200.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00

164	Turbine1	6.00	-0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
165	Fixed	-3200.00	-3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
166	Connect	-2724.51	-3200.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
167	Connect	-2560.09	-3200.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
168	Turbine2	-6.00	0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
169	Fixed	-2400.00	-2400.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
170	Connect	-2400.00	-2875.49	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
171	Connect	-2400.00	-3039.91	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
172	Turbine2	-0.00	6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
173	Fixed	-2400.00	-2400.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
174	Connect	-2400.00	-1924.51	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
175	Connect	-2400.00	-1760.09	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
176	Turbine3	-0.00	-6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
177	Fixed	-1600.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
178	Connect	-2075.49	-1600.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
179	Connect	-2239.91	-1600.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
180	Turbine3	6.00	-0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
181	Fixed	-1600.00	-1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182	Connect	-1124.51	-1600.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
183	Connect	-960.09	-1600.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
184	Turbine4	-6.00	0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
185	Fixed	-800.00	-800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
186	Connect	-800.00	-1275.49	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
187	Connect	-800.00	-1439.91	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
188	Turbine4	-0.00	6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
189	Fixed	-800.00	-800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
190	Connect	-800.00	-324.51	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
191	Connect	-800.00	-160.09	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
192	Turbine5	-0.00	-6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
193	Fixed	0.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
194	Connect	-475.49	-0.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
195	Connect	-639.91	-0.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
196	Turbine5	6.00	-0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
197	Fixed	0.00	0.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
198	Connect	475.49	0.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
199	Connect	639.91	0.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
200	Turbine6	-6.00	0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
201	Fixed	800.00	800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
202	Connect	800.00	324.51	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
203	Connect	800.00	160.09	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
204	Turbine6	-0.00	6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
205	Fixed	800.00	800.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
206	Connect	800.00	1275.49	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
207	Connect	800.00	1439.91	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
208	Turbine7	-0.00	-6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
209	Fixed	1600.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
210	Connect	1124.51	1600.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
211	Connect	960.09	1600.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
212	Turbine7	6.00	-0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
213	Fixed	1600.00	1600.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
214	Connect	2075.49	1600.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
215	Connect	2239.91	1600.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
216	Turbine8	-6.00	0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
217	Fixed	2400.00	2400.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
218	Connect	2400.00	1924.51	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
219	Connect	2400.00	1760.09	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
220	Turbine8	-0.00	6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
221	Fixed	2400.00	2400.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
222	Connect	2400.00	2875.49	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
223	Connect	2400.00	3039.91	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
224	Turbine9	-0.00	-6.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225	Fixed	3200.00	3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
226	Connect	2724.51	3200.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
227	Connect	2560.09	3200.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
228	Turbine9	6.00	-0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
229	Fixed	3200.00	3200.00	-600.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
230	Connect	3675.49	3200.00	-404.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
231	Connect	3839.91	3200.00	-210.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00
232	Turbine10	-6.00	0.00	-30.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

```
---------------------- LINE PROPERTIES -----------------------------------------------------
183    NLines    - number of line objects
Line       LineType    UnstrLen  NumSegs  NodeAnch  NodeFair  Outputs  CtrlChan
(-)          (-)         (m)       (-)       (-)       (-)       (-)       (-)
1    segment2          45.359    3         3         1         -   0
2    segment2          45.359    3         3         2         -   0
3    segment2          54.641    3         3         4         -   0
4    segment1        1363.073    20        4         5         -   0
5    segment2          45.359    3         8         6         -   0
6    segment2          45.359    3         8         7         -   0
7    segment2          54.641    3         5         8         -   0
8    segment2          45.359    3         11        9         -   0
9    segment2          45.359    3         11        10        -   0
10   segment2          54.641    3         11        12        -   0
11   segment1        1363.073    20        12        13        -   0
12   segment2          45.359    3         16        14        -   0
13   segment2          45.359    3         16        15        -   0
14   segment2          54.641    3         13        16        -   0
15   segment2          45.359    3         19        17        -   0
16   segment2          45.359    3         19        18        -   0
17   segment2          54.641    3         19        20        -   0
18   segment1        1363.073    20        20        21        -   0
19   segment2          45.359    3         24        22        -   0
20   segment2          45.359    3         24        23        -   0
21   segment2          54.641    3         21        24        -   0
22   segment2          45.359    3         27        25        -   0
23   segment2          45.359    3         27        26        -   0
24   segment2          54.641    3         27        28        -   0
25   segment1        1363.073    20        28        29        -   0
26   segment2          45.359    3         32        30        -   0
27   segment2          45.359    3         32        31        -   0
28   segment2          54.641    3         29        32        -   0
29   segment2          45.359    3         35        33        -   0
30   segment2          45.359    3         35        34        -   0
31   segment2          54.641    3         35        36        -   0
32   segment1        1363.073    20        36        37        -   0
33   segment2          45.359    3         40        38        -   0
34   segment2          45.359    3         40        39        -   0
35   segment2          54.641    3         37        40        -   0
36   segment2          45.359    3         43        41        -   0
37   segment2          45.359    3         43        42        -   0
38   segment2          54.641    3         43        44        -   0
39   segment1        1363.073    20        44        45        -   0
40   segment2          45.359    3         48        46        -   0
41   segment2          45.359    3         48        47        -   0
42   segment2          54.641    3         45        48        -   0
43   segment2          45.359    3         51        49        -   0
44   segment2          45.359    3         51        50        -   0
45   segment2          54.641    3         51        52        -   0
46   segment1        1363.073    20        52        53        -   0
47   segment2          45.359    3         56        54        -   0
48   segment2          45.359    3         56        55        -   0
49   segment2          54.641    3         53        56        -   0
50   segment2          45.359    3         59        57        -   0
51   segment2          45.359    3         59        58        -   0
52   segment2          54.641    3         59        60        -   0
53   segment1        1363.073    20        60        61        -   0
54   segment2          45.359    3         64        62        -   0
55   segment2          45.359    3         64        63        -   0
56   segment2          54.641    3         61        64        -   0
57   segment2          45.359    3         67        65        -   0
58   segment2          45.359    3         67        66        -   0
59   segment2          54.641    3         67        68        -   0
60   segment1        1363.073    20        68        69        -   0
61   segment2          45.359    3         72        70        -   0
62   segment2          45.359    3         72        71        -   0
63   segment2          54.641    3         69        72        -   0
64   polyester213      45.359    3         76        74        -   0
65   polyester213      45.359    3         76        75        -   0
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66	polyester213	1595.032	20	73	76	-	0
67	polyester213	45.359	3	80	78	-	0
68	polyester213	45.359	3	80	79	-	0
69	polyester213	1595.032	20	77	80	-	0
70	polyester213	45.359	3	84	82	-	0
71	polyester213	45.359	3	84	83	-	0
72	polyester213	1595.032	20	81	84	-	0
73	polyester213	45.359	3	88	86	-	0
74	polyester213	45.359	3	88	87	-	0
75	polyester213	1595.032	20	85	88	-	0
76	polyester213	45.359	3	92	90	-	0
77	polyester213	45.359	3	92	91	-	0
78	polyester213	1595.032	20	89	92	-	0
79	polyester213	45.359	3	96	94	-	0
80	polyester213	45.359	3	96	95	-	0
81	polyester213	1595.032	20	93	96	-	0
82	polyester213	45.359	3	100	98	-	0
83	polyester213	45.359	3	100	99	-	0
84	polyester213	1595.032	20	97	100	-	0
85	polyester213	45.359	3	104	102	-	0
86	polyester213	45.359	3	104	103	-	0
87	polyester213	1595.032	20	101	104	-	0
88	polyester213	45.359	3	108	106	-	0
89	polyester213	45.359	3	108	107	-	0
90	polyester213	1595.032	20	105	108	-	0
91	polyester213	45.359	3	112	110	-	0
92	polyester213	45.359	3	112	111	-	0
93	polyester213	1595.032	20	109	112	-	0
94	polyester213	45.359	3	116	114	-	0
95	polyester213	45.359	3	116	115	-	0
96	polyester213	1595.032	20	113	116	-	0
97	polyester213	45.359	3	120	118	-	0
98	polyester213	45.359	3	120	119	-	0
99	polyester213	1595.032	20	117	120	-	0
100	polyester213	45.359	3	124	122	-	0
101	polyester213	45.359	3	124	123	-	0
102	polyester213	1595.032	20	121	124	-	0
103	polyester213	45.359	3	128	126	-	0
104	polyester213	45.359	3	128	127	-	0
105	polyester213	1595.032	20	125	128	-	0
106	polyester213	45.359	3	132	130	-	0
107	polyester213	45.359	3	132	131	-	0
108	polyester213	1595.032	20	129	132	-	0
109	polyester213	45.359	3	136	134	-	0
110	polyester213	45.359	3	136	135	-	0
111	polyester213	1595.032	20	133	136	-	0
112	polyester213	45.359	3	140	138	-	0
113	polyester213	45.359	3	140	139	-	0
114	polyester213	1595.032	20	137	140	-	0
115	polyester213	45.359	3	144	142	-	0
116	polyester213	45.359	3	144	143	-	0
117	polyester213	1595.032	20	141	144	-	0
118	polyester213	45.359	3	148	146	-	0
119	polyester213	45.359	3	148	147	-	0
120	polyester213	1595.032	20	145	148	-	0
121	polyester213	45.359	3	152	150	-	0
122	polyester213	45.359	3	152	151	-	0
123	polyester213	1595.032	20	149	152	-	0
124	polyester213	45.359	3	156	154	-	0
125	polyester213	45.359	3	156	155	-	0
126	polyester213	1595.032	20	153	156	-	0
127	polyester213	45.359	3	160	158	-	0
128	polyester213	45.359	3	160	159	-	0
129	polyester213	1595.032	20	157	160	-	0
130	cable	600.000	20	161	162	-	0
131	buoyancy	300.000	20	162	163	-	0
132	cable	280.000	20	163	164	-	0
133	cable	600.000	20	165	166	-	0
134	buoyancy	300.000	20	166	167	-	0

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135  cable           280.000    20      167       168        -   0
136  cable           600.000    20      169       170        -   0
137  buoyancy        300.000    20      170       171        -   0
138  cable           280.000    20      171       172        -   0
139  cable           600.000    20      173       174        -   0
140  buoyancy        300.000    20      174       175        -   0
141  cable           280.000    20      175       176        -   0
142  cable           600.000    20      177       178        -   0
143  buoyancy        300.000    20      178       179        -   0
144  cable           280.000    20      179       180        -   0
145  cable           600.000    20      181       182        -   0
146  buoyancy        300.000    20      182       183        -   0
147  cable           280.000    20      183       184        -   0
148  cable           600.000    20      185       186        -   0
149  buoyancy        300.000    20      186       187        -   0
150  cable           280.000    20      187       188        -   0
151  cable           600.000    20      189       190        -   0
152  buoyancy        300.000    20      190       191        -   0
153  cable           280.000    20      191       192        -   0
154  cable           600.000    20      193       194        -   0
155  buoyancy        300.000    20      194       195        -   0
156  cable           280.000    20      195       196        -   0
157  cable           600.000    20      197       198        -   0
158  buoyancy        300.000    20      198       199        -   0
159  cable           280.000    20      199       200        -   0
160  cable           600.000    20      201       202        -   0
161  buoyancy        300.000    20      202       203        -   0
162  cable           280.000    20      203       204        -   0
163  cable           600.000    20      205       206        -   0
164  buoyancy        300.000    20      206       207        -   0
165  cable           280.000    20      207       208        -   0
166  cable           600.000    20      209       210        -   0
167  buoyancy        300.000    20      210       211        -   0
168  cable           280.000    20      211       212        -   0
169  cable           600.000    20      213       214        -   0
170  buoyancy        300.000    20      214       215        -   0
171  cable           280.000    20      215       216        -   0
172  cable           600.000    20      217       218        -   0
173  buoyancy        300.000    20      218       219        -   0
174  cable           280.000    20      219       220        -   0
175  cable           600.000    20      221       222        -   0
176  buoyancy        300.000    20      222       223        -   0
177  cable           280.000    20      223       224        -   0
178  cable           600.000    20      225       226        -   0
179  buoyancy        300.000    20      226       227        -   0
180  cable           280.000    20      227       228        -   0
181  cable           600.000    20      229       230        -   0
182  buoyancy        300.000    20      230       231        -   0
183  cable           280.000    20      231       232        -   0
---------------------- SOLVER OPTIONS ----------------------------------------
0.001    dtM          - time step to use in mooring integration (s)
600.0    depth        - water depth (m) <<< must be specified for farm-level mooring
3.0e+06  kbot         - bottom stiffness (Pa/m)
3.0e+05  cbot         - bottom damping (Pa-s/m)
2.0      dtIC         - time interval for analyzing convergence during IC gen (s)
10.0     TmaxIC       - max time for ic gen (s)
4.0      CdScaleIC    - factor by which to scale drag coefficients during dynamic relaxation (-)
0.01     threshIC     - threshold for IC convergence (-)
----------------------------OUTPUTS--------------------------------------------
FairTen1
FairTen2
FairTen3
END
--------------------- need this line ------------------
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