Overview of Floating Offshore Wind Technologies

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In this chapter a review of the key technology components that can be directly associated with FOWTs is presented. The main options for the key technology component that make up a FOWT are discussed in detail, namely the types of support structures (Sect. 1), wind turbines (Sect. 2) and mooring systems (Sect. 3). The main objective of this chapter is to provide the reader with a clear overview of the relative advantages and disadvantages of each key design option.

1 Support Structures for Floating Wind Turbines

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Similar to the bottom-fixed case, there is a wide range of candidate types of floating foundations, this being liberally demonstrated by the variety of full-scale prototype units in the water or under construction today, in Norway, Portugal and Japan with a further unit under assembly for the German Baltic Sea.

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This section explores the fundamental diversity of floater concept designs, and explains some of the considerations that drive the engineering decisions, with the section being laid out as follows:

- *Floater Concept Identification*: how do the different types of concepts arise? Why are they so different?
- *Floater Concept Selection*: how can the foundation types be assessed? Why might one concept be more suitable for a particular site?
- *Floater Concept Description*: understanding the strengths and weaknesses of each foundation type.

How the foundation counters the wind turbine overturning thrust load and achieves stability is arguably the primary design driver and hence foundation types can be conveniently classified accordingly:

- Spar concepts, which use gravity in the form of ballast,
- Semi-submersible concepts, which use distributed buoyancy, similar to a catamaran,
- Tensioned-moored concepts, which use taut moorings.

In reality, any floater type will use a combination of the above to achieve stability, and there is a *continuum* of intermediate designs. However, usually one method for achieving stability will dominate, leading to clear differences in how the floater concepts are constructed and installed.

Water depth arguably will have the greatest influence on the selection of floater concept, however ground conditions will determine the choice of anchoring methods, which might have a knock-on effect on the floater type, whilst design and fabrication experience, including from the offshore oil and gas sector, risk appetite, and IP (intellectual property) considerations will also affect the selection.

The weight and cost of bottom-mounted wind turbine foundation structures for deeper waters generally increases exponentially with depth, thus challenging the offshore wind energy industry's cost reduction goals. Similarly, floating foundations are larger and costlier than the foundations at the shallowest water sites originally developed in the industry's earliest years. However, the current generation of very large wind turbines should deliver lower foundation costs for floating platforms, in the same manner as such wind turbines do for bottom-mounted monopiles, jackets and GBSs (gravity base structures).

On another positive note, compared with bottom-mounted designs, costs of floating platforms are less sensitive to increases in water depth, since only the mooring costs are sensitive to water depth, with the platform structure costs being mainly unaffected by depth. This can be understood by considering how the wind turbine loads are transferred. For a conventional bottom-fixed foundation, the loads are transferred deep within the seabed through a rigid structure. Whilst this does provide a stable platform and is now well understood by wind turbine and foundation design engineers, the load path is lengthy and bending loads can be severe. In contrast, a floating platform transfers the primary wind turbine loads to the water, which has two important advantages: firstly, the water is closer, hence the load path is shorter and in particular, the bending moments will be commensurately lower; and secondly, water is compliant, hence there is dynamic flexibility and the peak forces can potentially be lower.

However, the dynamics of a floating foundation does introduce some new challenges, including:

- minimising the wind turbine and wave induced motion;
- minimising the wind turbine and wave induced static displacement, i.e. heel (fore-aft rotation) and surge (horizontal displacement);
- modelling the complete system and the effect that the additional motion will have on the wind turbine;
  - including understanding and modelling the coupling between the support structure (including moorings) and the wind turbine (including controller);
- understanding what the design limits should be; relaxing specific design limits could prove beneficial for the foundation, hence each design driver should be carefully examined, challenged and justified;
- understanding the dynamic effects on the electrical cable exporting the power from the platform.

In summary, utilisation of floating support structures can deliver a number of important benefits, principally:

- greater choice of sites and countries, as well as reduced penalty for variability in water depth and ground conditions across a site;
- wide and flexible choice of concepts; as evidence view the wide variety of technology solutions proposed and being demonstrated;
- the most cost optimal foundation concept for deeper water; the future will show where the transition water depth is;
- good flexibility of construction and installation procedures;
- easier removal, relocation and decommissioning.

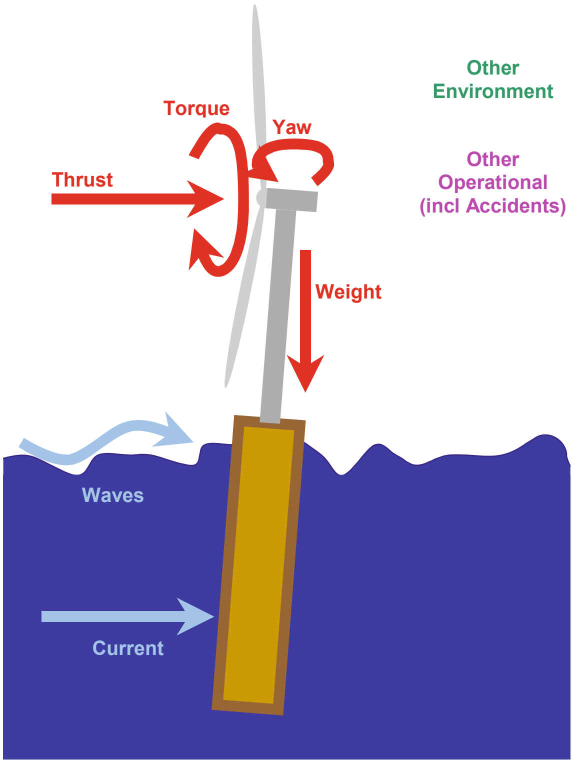
1.1 Concept Identification

A floating support structure can be broken down into the following systems:

- Structure (floater, platform): maintain buoyancy and structural integrity;
- Mooring: connect the floater to the seabed, typically chain or cables;
- Anchoring: attach the mooring lines to the seabed;
- Electrical cable: export of power.

The focus of this section is the first item: the main structure or platform. In essence, the foundation concept must support the wind turbine. It needs to react to and transmit loads whilst maintain stability and station-keeping. Examining these

Fig. 1 Principal design loads



technical aspects in more detail, a floating foundation will experience the following types of loads (see also Fig. 1; further details on design loads for FOWTs are also presented in Sect. 1 in Chapter "Key Design Considerations"):

- Wind-induced loads on the wind turbine rotor,
  - Considering both the mean and the dynamic components,
  - Considering both shear and bending moments,
  - Considering the thrust, torque and yaw axes;
- Wave-induced loads on the floater as well as associated secondary structures, such as landing platforms and J-tubes,
  - Considering both the static (drift force) and the dynamic components,
  - Considering both shear and bending moments;
- Ocean current induced loads on the floater,
  - Including vortex shedding loads,
  - Consider misalignment between wind, waves and currents;
- Sea-level induced loads on the floater, for example due to tides;
- Weight of the wind turbine and floater;

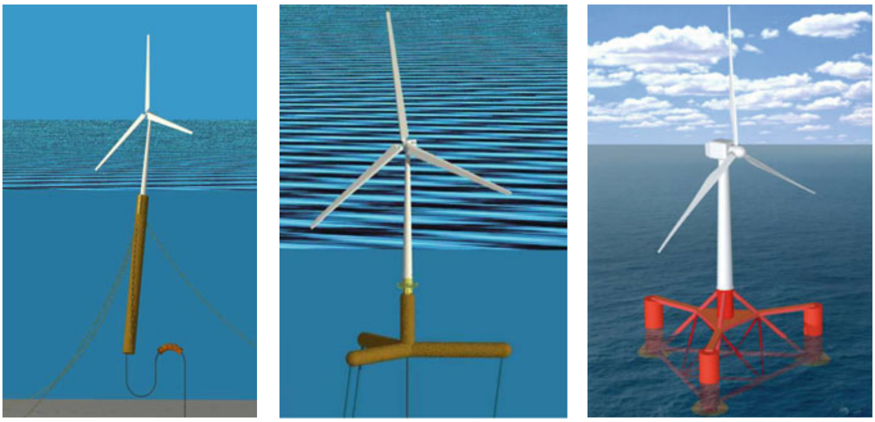
- Other environmental loads, such as icing;
- Accident and fault loads, for example:
  - Wind turbine fault conditions,
  - Water-tightness failure of buoyancy chambers;
- And finally other incidental and miscellaneous loads, such as:
  - dynamic response of the export cable,
  - wind loading on the tower.

Of the sources of loading listed, the *mean wind turbine thrust overturning moment* can be considered the primary design driver. Consequentially the basic structure of the floater will be developed to counter this load and the method taken to do so will determine the basic shape. There are three methods (see Fig. 2):

- Ballast stabilised: leads to a slender vertical structure, i.e. the spar platform,
- Buoyancy-stabilised, through hydrostatics: leads to a large surface structure, i.e. the semi-submersible platform,
- Mooring-stabilised, through taut lines: leads to a slender highly loaded submerged structure, i.e. the tensioned-moored or tension-leg platform (TLP).

The geometry of the floating platform will depend on which method is chosen to counter the wind turbine loads, thus driving the multiplicity in designs that is evident in the floating wind sector.

All the above design approaches are technically and practically viable and indeed all are being actively pursued. Each class of platform has different characteristics and strengths: the spar and semi-submersible type floater has the benefit of



Spar Class *(Ballast Stabilised)* ***TLP Class*** *(Moorings Stabilised)* ***Semi-Submersible Class*** *(Buoyancy Stabilised)*

Fig. 2 Support structure classes

using predominantly widely used and proven technology, while the tensioned and semi-submersible type floater can be used in shallower waters than the spar and for the tensioned floater, a lightweight elegant design may be ultimately achievable.

Concepts Comparison and Selection
The key criteria for the evaluation and selection of floating foundation platforms will be:

- Motion response and Station-keeping,
  - Ability to maintain the wind turbine within operating and extreme envelope.
- Structural loading,
  - Ability to withstand extreme conditions at the site.
- Maturity of the design,
  - Including credible and comprehensive modelling capability, calibrated against scale and full size platforms.
- Fabrication and Installation,
  - Ease and confidence in manufacturing techniques as well as installation methods.
- Safety,
  - Building on experience in the onshore and offshore wind sectors as well as other marine sectors.

Examining each criterion to greater detail in turn:

- Motion response needs to remain within the envelope acceptable to the wind turbine, however firstly it needs to be acknowledged that this is a novel question for the wind turbine suppliers and hence cannot be answered without analytical effort and cautious testing thus building up practical experience. In general, an appropriately designed floating platform will experience predominantly low accelerations and hence manageable wave-motion-induced loads; this is because the largest amplitude waves inevitably have long periods with associated slower movements and accelerations; conversely, the short period waves, which could cause high accelerations to very small floating structures, are short as well as with relatively low heights, due to breaking wave height-limits; the short lengths mean the platform will move less in response, since the waves will have a similar dimension as the structure itself. As a result, the accelerations and loads experienced by the wind turbines on a floating platform are not exceptionally severe and indeed are broadly similar to those experienced by onshore and fixed-offshore wind turbines; this has been demonstrated by prototypes and matches well with conclusions from modelling work. It should be appreciated that onshore wind turbines can experience very high accelerations and loads, for example due to extreme gusts at turbulent sites in mountainous terrain, or emergency shut-down events, hence wind turbines are designed for such conditions.

- Many platform designs, specifically spars and semi-submersible structures, use the restoring forces generated by the platform heel (leaning backwards) to counter the turbine thrust load, hence the wind turbine will be at an angle of a few degrees during normal operations; this never occurs for an onshore or bottom-fixed offshore wind turbine of course, hence there is no experience to guide setting appropriate design limits, bearing in mind that this design criteria will directly impact the size and hence cost of the floating foundation, indicatively in a linear manner. The wind turbine industry does have experience of the resulting misalignment of the wind inflow, firstly since rotors are invariable tilted by a few degrees and secondly since flow directions in complex terrain can deviate by an order of magnitude higher;
- Some platform designs, specifically spar and TLP concepts, provide very little upwind yaw-stability; it should be born in mind that conventional three-bladed upwind turbines are stable, i.e. for small misalignments with the wind direction, the net yaw forces will cause the wind turbine rotor to restore back into the wind; unfortunately it does need to be acknowledged that this yaw moment is challenging to accurately calculate using state-of-the-art methods and models hence some conservatism and contingency planning (for example, anticipation to tune the wind turbine controller) will be required; the yaw restoring moment itself needs to be provided by the moorings, requiring a non-negligible misalignment in the case of slack moorings;
- Waves induce both a dynamic as well as a mean or static force on a structure, this later being smaller but significant and called the drift force, hence the moorings will need to generate a restoring force;
- Coupling between modes of motion will occur, for both the floater and the wind turbine; an interesting example is the yaw moment generated from the rotor torque when the wind turbine drive train is inclined. The inclination due to the rotor tilt will be increased if the floater heels to counter the thrust force. It is noted that larger turbines have slower rotational speeds, hence generate proportionately higher torque loads;
- Any additional inclination of the rotor caused by the platform heeling over during operation could cause a small reduction to power production due to the further misalignment with the wind direction; however, this is likely to be non-material.

• The loads on the floater and wind turbine structure need to be accurately calculated and designed for; a number of coupled software suites are capable of modelling seabed-fixed offshore wind turbines with some models also able to simulate the low-frequency high-amplitude motion that is unique to floating wind turbines (see also Sect. 5 in chapter “Modelling of Floating Offshore Wind Technologies” for a review of numerical modelling design codes for FOWT applications):

- Regarding modelling of the wind turbine, key challenges include modelling the wind-field and the controller; the wind-field is modelled in a statistical rather than a deterministic manner, of course, making validation of new floating-specific features of the code more difficult; to date validation has focused on code-to-code comparisons however for the floater design to be fully optimised, code-to-measurements validation will be required; installing a full suite of calibrated instruments on the demonstration units and employing suitable technical expertise can achieve this goal;
- Regarding modelling of the floater, key challenges include diffraction coupled with surface effects as well as mooring line dynamics; diffraction modelling will mainly be required for floaters with a large structure at or near the water surface, specifically semi-submersible platforms though TLP floaters in shallow water could include elements at a short distance below the surface; diffraction analysis is usually run in a linear manner, assuming infinitesimal wave heights and hence ignoring wave run up and temporary submergence of parts of the structure; mooring line dynamics is arguably the most challenging feature for offshore software, specifically for slack moorings;
- For the foreseeable future, wind turbine design adjustments for the benefit of floating deployments will likely be limited to controller design and tuning and possible some O&M (operation and maintenance) processes however in the longer term there may be benefits of including floating wind energy drivers as priorities in the fundamental wind turbine design; the key objective is minimising nacelle weight: depending on the floater concept, for each tonne saved in the nacelle, several tonnes will be saved in the platform; more sophisticated wind turbine design adaptations could include design for horizontal transport and ballast-driven horizontal-to-vertical installation methods;
- In general, it can be assumed that the additional loads on the wind turbine itself caused by the motion of the floating platform will be minimal and unlikely to require any material design changes to the wind turbine rotor-nacelle assembly (RNA), such as requirements for a more robust wind turbine class; this will not be the case for the wind turbine tower, which will require a site and platform specific design; reinforcements will be necessary to mitigate additional fatigue loading as well as the default inclined operating orientation of spar buoy and some semi-sub concepts.

• Maturity of the design:

  - Floating wind turbine foundations are novel and indeed the degree of novelty can be accentuated by a desire to achieve step changes in performance and cost and to stake out patentable IP (intellectual property), irrespective of overall technology risk; however there will be many aspects similar to existing wind energy and offshore engineering technologies where existing design, fabrication, installation and operation experience can be utilised; a suitable balance needs to be found between incorporating necessary novel

features, in order to achieve a successful design and to lower the cost of energy, and deploying existing proven technologies, in order to manage overall risk; arguably, during this stage of industry immaturity, floating wind energy projects should be inclined towards the latter;
- For the novel design aspects, a comprehensive programme of credible modelling and testing is necessary, including scale testing for the floater assembly (noting that wind turbines do not scale successfully, hence there will be no benefits from scale tests to the wind turbines themselves) and simulation-model development for the turbine and the complete system, calibration against full-scale prototypes and a wide-ranging programme of simulations, preferably extending well beyond current standards the risks that need to be minimised include unexpected phenomena as the operational envelope is extended; such phenomena have affected both the wind energy and offshore industries in the past and can be expensive and time-consuming to resolve in the field, historic examples include wind turbine blade edge-wise vibration and spar and mooring line VIV (vortex-induced vibrations);
- The offshore engineering industry has a long history of developing and implementing novel fixed and floating concepts; the functional specifications to support a drilling rig or well service plant at a new development field can be unique and unusual compared with traditional marine engineering requirements, for example in terms of anchoring water depth, survival wave climates, payloads, processing of flammable liquids, manning levels etc. there have been many successes from which floating wind is already benefitting from, in terms of the technologies themselves as well as the processes used to mature new platforms;
- Finally, the design process should prioritise fabrication and installation equally as the more obvious objective of optimal in-field performance.

- Fabrication and Installation:
  - The issues elaborated within the previous paragraphs on design also relate to fabrication and installation; for fabrication, standardised processes should be available, for example monopile fabrication methods for spar buoys (which in turn originated at high pressure boiler manufacturers), fabrication-optimised jacket methods for more complex steel structures whilst marine and coastal assembly methods could be suitable for concrete platform types;
  - Monopiles are most successfully assembled in efficient and well laid-out facilities, where automated processes, material flow and quality control is prominent; the cost of raw material will be a similar order of magnitude as the cost of fabrication;
  - For more complex steel structures, such as bottom-mounted jackets or floating semi-sub platforms, the costs of fabrication and assembly will dominate the costs of the raw materials, hence a *fabrication-optimised* design will deliver a lower cost of energy compared with a *weight-optimised* design;

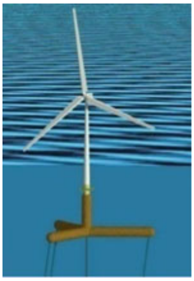
this could focus on welding types, weld geometry, material handling, fabrication of sub-assemblies as well as the platform itself, effectiveness of quality control, general automation amongst other factors;
  - Installation should be an integral platform design objective, and indeed for some platform concepts, in particular spar buoys and TLPs, installation may prove to be the primary objective for successful platforms; credibility of installation methods will depend on metocean climate at site and en-route, in particular wave climate, but in some cases also currents and wind regime;
  - For spar buoys, the key installation challenge is transporting a deep-draft platform from the shallow assembly harbour (the deep and enclosed Norwegian fjords being a notable and worldwide unique exception) to the deeper windfarm site and then upending the platform; the oil and gas industry has typically achieved this by transferring ballast to the spar-base, thus changing the stability of the spar and causing it to upend; in the oil and gas industry, this will be undertaken without the topside, which would require a suitable very-calm weather window to complete; for offshore windfarms, it might be possible to pre-install the wind turbine in the horizontal and upend the fully assembled structure at site;
  - For TLPs, the key installation challenge is the transition from a stable float-out where the main horizontal structure is at the sea-surface to the stable in-service configuration where the main horizontal structure has been pulled down below the sea surface and the structure is under tension; both start and end situation are reasonably stable, however the transition itself will not be stable;
  - However perhaps installation can also be considered an opportunity; whilst the challenges are significant, credible if costly installation methods are available and engineering ingenuity may propose successful novel solutions from the apparently infinite range of opportunities that the blank canvass of a flexible platform topology, experience within the offshore industry of a myriad of platform concepts and an open sea offers.

- Safety:
  - For a successful birth of the floating offshore wind industry, safety must be paramount and should reflect the professionalism and diligence required to achieve such a challenging goal of establishing a new renewable energy sector; much experience can be transferred from the existing onshore and offshore wind sectors as well as other marine sectors, such as coastal engineering and oil and gas.

In summary, design objectives for floating wind energy platforms need to encompass fabrication and installation and not just in-service operation; factors for evaluation of candidate platform types could include:

- Site conditions, in particular water depth and sea climate;
- Controlling turbine and wave induced motion;

Table 1 Assessment of floating platform classes

	Spar	TLP	Semi-Sub
			
Stability	Ballast	Moorings	Hydrostatics
Min depth [a]	Deeper	Shallower	Shallower
Periods	Good	Good	Acceptable
Cost	Uncertain	Uncertain	Uncertain
Yaw and torque	Acceptable	Probably good	Good
Fabrication	Potentially simple structure	More complex structure	More complex structure
Installation	More complex operation	More complex operation	Good

[a]However greater depths will typically allow a better performing and lower cost design to be deployed

- Managing the greater complexity of the design process, including understanding and modelling the coupling between the support structure and the wind turbine (in particular moorings & control);
- The electrical infrastructure design and costs, in particular the flexible cable;
- The construction, installation and O&M procedures, in particular similar attention should be paid to installation as to the operation.

Table 1 presents a high-level evaluation of the three offshore floating platform classes. It can be seen that each has advantages and disadvantages, hence it is likely that more than one type of foundation platform will become established, in particular one concept for shallower and another for deeper waters.

1.2 Spar Buoy Class of Platforms

Examining the spar concept first in greater detail, Fig. 3 shows the key characteristics and components.

Due to the fact that the platform must support a major horizontal load at a significant height above the sea level, designing a successful floating offshore wind

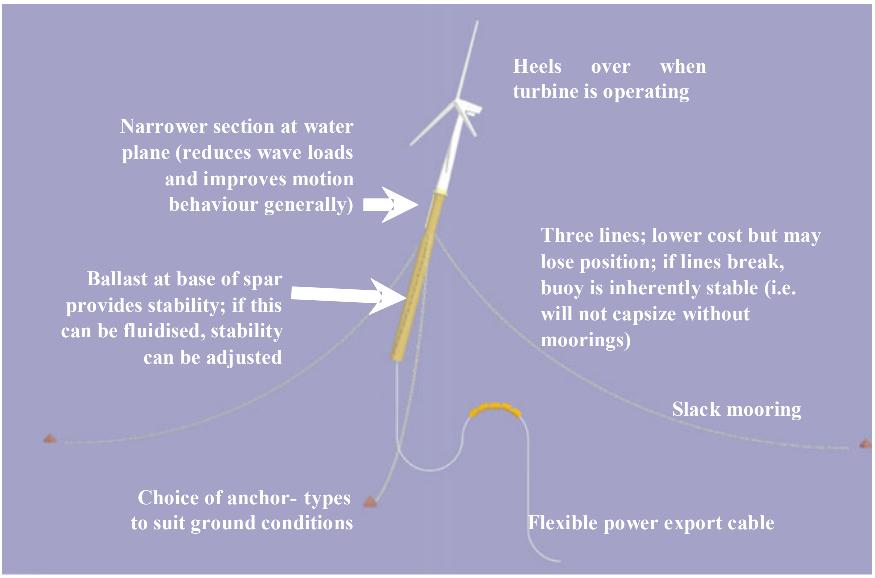


Fig. 3 Spar buoy—summary of the technical details

spar concept is arguably a more interesting engineering challenge compared with oil and gas designs. Figures 4 and 5 illustrate this, starting with the process of balancing the conflicting requirements from selected principal design drivers.

Figure 4 shows how three design drivers:

(i) maximising pitch stiffness in order to minimise vessel heel,
(ii) maximising the natural heave period in order to reduce wave induced motion and
(iii) minimising cost

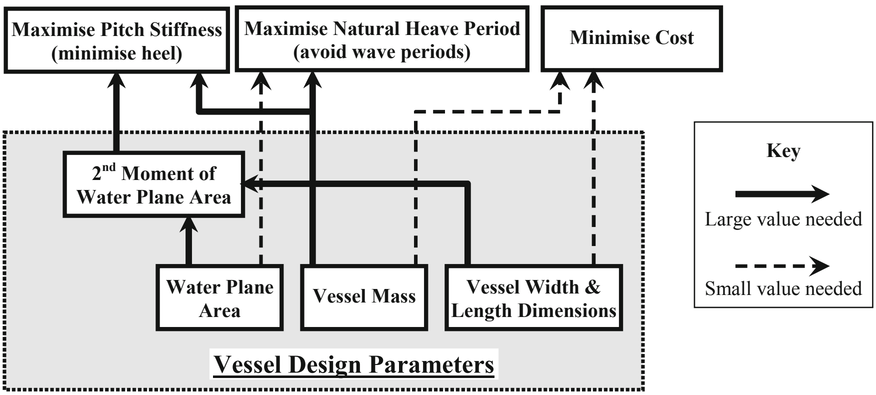


Fig. 4 Conflict between design drivers

drive conflicting demands on the vessel design parameters. There are demands on the water plane area, vessel mass and vessel dimensions to be simultaneously as large as possible and as small as possible.

The consequence of these conflicting design drivers is that the suitable design space is very limited and involves compromise; Fig. 5 illustrates this graphically for a matrix of all configurations of spar length and spar diameter, i.e. the extremes in terms of spar length and diameter are shown in each corner of the figure. The overwhelming majority of spar configurations are not technically viable for a wide range of differing reasons.

The viable design-space is small and is bounded by design limiting criteria for:

(i) stability;
(ii) vertical motion (heave natural period);
(iii) pitching motion (fore-aft rotational natural period);
(iv) cost (overall size of the spar), and
(v) fatigue criteria.

Invariable a certain degree of compromise with these criteria will be necessary. If larger wind turbines are used, the size of the acceptable design-space does increase, in particular since the larger spar will have longer natural periods in heave and roll/pitch. However, a disadvantage for larger wind turbines is that the minimum water depth also increases hence some windfarm project opportunities might be lost.

Figure 5 provides a visual presentation of the viability of a matrix of conceptual designs, for increasing spar buoy diameter (left-to-right) and increasing spar buoy length (top-to-bottom). The diagram shows the viable design space and why other designs are not feasible, due to excessive motion, instability, fatigue and cost.

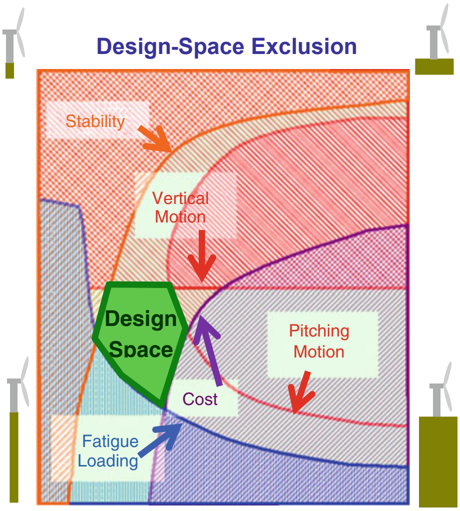


Fig. 5 Identifying the optimal design space

In summary, the principal challenges in delivering a successful spar buoy concept are anticipated to be:

- controlling the size of the spar buoy structure;
  - negotiating the static and dynamic motion limits required for the wind turbine;
- strengthening the wind turbine tower to cope with the bending moment induced by the heel during normal operation, as well additional loading due to motion during transport, installation and operation;
- assembly of the wind turbine on to the spar buoy; in the enclosed deep waters of the Norwegian fjords, this can be done in the vertical, but most locations will not allow this off-site; in such cases horizontal tow-out and upending will be necessary, this being the conventional approach in the offshore engineering industry; waiting for weather-windows at the inevitably exposed and windy project site will involve lengthy delays to installation.

1.3 Tensioned Moored Class of Platforms

Turning to the TLP (Tensioned Leg Platform) concept and examining this in greater detail, Fig. 6 shows the key characteristics and components. The concept is also known as a TBP (Tensioned Buoyant Platform).

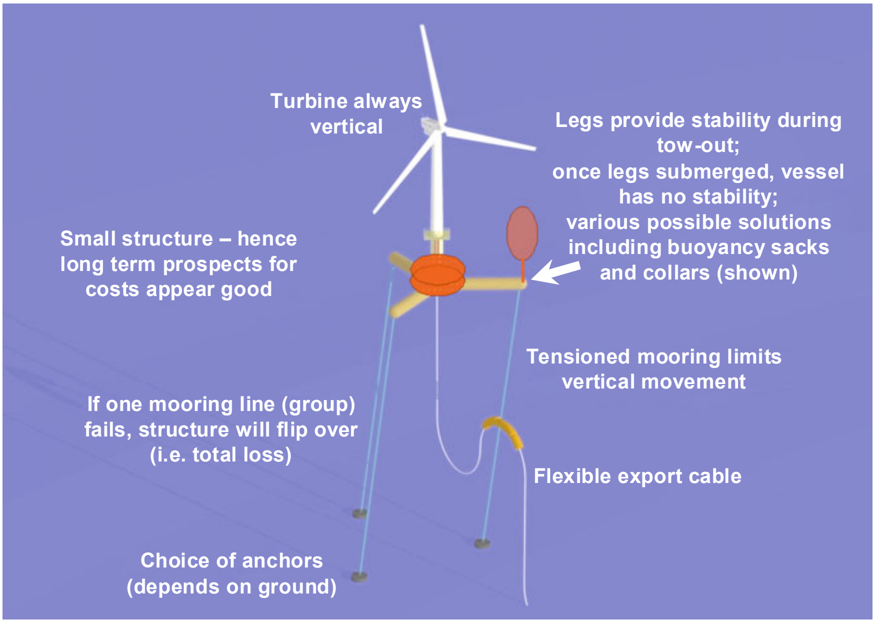


Fig. 6 TLP—summary of the technical details

Due to the unextendable mooring lines, TLPs are the most stable platform-class, once in the fully installed position. Since the mooring lines are designed to be axially rigid, there is typically no significant heave (vertical) motion, nor roll (forward inclination) and pitch (sideways inclination). There will be surge (forward) and sway (sideways) translational motion as well as yaw motion.

Assuming that the wind turbine will be installed at the quayside, the installation of the complete structure at site will be more challenging than the alternative concepts. Although the fully-assembled TLP can be designed to float stably on the sea-surface during tow-out, and will also be stable once installed, TLPs will be vulnerable to instability during the installation process on site. During tow-out, buoyancy aids may be required to avoid capsizing in waves, with such aids being imperative during the installation process, as the structure is tensioned downwards to its operating configuration. Buoyancy and stability could be provided by buoyancy collars, sacks or chambers, which should be removed once installed to reduce operational wave loading. Alternatively, a vessel-assisted installation operation could be mounted, using a specialist barge or offshore service vessel, noting that bespoke modification can be expensive and can reduce the attractiveness of the vessel to other customers.

The concept has low stiffness against surge and sway forces, with the reactive force being generated by inclination of the mooring lines. However, this inclination of the mooring line will cause the platform to drop downwards further into the water, the exact response being dependant on the water depth and mooring design details. This response is termed *set-down*.

Since the vertical position of the platform is fixed by the mooring tendons, the structure is unable to move vertically in response to changes in sea-level in particular caused by tides. Tidal ranges are highly site dependent, with some seas such as the Baltic and the Mediterranean experiencing negligible tides, whilst other locations observe tidal ranges as high as 10 m, for example where local and regional seabed topology funnels tidal flows from major oceans towards particular bays and channels. A mooring system that responds dynamically to this change in sea level is not practical for reliability and safety reasons.

Related to this is a key operational risk suffered by TLP structures, in that the mooring lines are designed to be taut and straight and must remain so. If the tension is removed, the lines will flex temporarily and when the tension is restored will experience snap loads, likely to result in instant or eventual failure. Loss of one tendon in a three or four tendon system will be catastrophic.

Loss of tension in the mooring lines is caused by changes in the instantaneous water surface level, which might most commonly be caused by tidal variations or extreme waves. Hence waves that exceed design limits might cause the complete loss of the TLP platform and wind turbine rather than repairable damage. Failure of mooring lines will typically result in capsizing of the vessel and hence complete loss. Whilst spar and semi-submersible platforms are themselves inherently stable, the TLP structure is inherently unstable and entirely dependent on the mooring lines to provide stability.

TLP mooring lines impose vertical loads on the anchor points, which differs from forces associated with slack mooring lines which can be either entirely horizontal or a combination of horizontal and vertical loads. The vertical loading will require particular types of anchoring, with gravity-type, suction-caissons and piles being the leading candidates and all arguably being less attractive than further options available only to spar and semi-submersible platforms, such as drag anchors. Gravity anchors will inevitably be massive and expensive to fabricate, transport and install, whilst suction-caisson and piled anchors are challenging to design, are sensitive to and restricted to certain soil conditions and have a limited operational track record at the depths being considered.

As is elaborated in the preceding paragraphs, the challenges in developing a successful TLP design are significant and involve greater risks than spar and semi-submersible platforms. It is not clear at this stage whether this design challenge will be surmountable in a cost effective manner. However, if a successful TLP design can be found for offshore wind turbines, there is potential for a light-weight, elegant and hence low-cost offshore wind foundation, deployable across a very wide range of water depths, including relatively shallow sites and being able to successfully compete against the alternative of bottom-mounted foundations.

1.4 Semi-Submersible Class of Platforms

Turning to the semi-submersible class of platforms, which typically can be described as a floating jacket or space-frame and examining this in greater detail, Fig. 7 shows the key characteristics and components of a four column floater.

There are numerous variations of this concept, for example:

- With either three of four primary columns;
- With the turbine either at the centre or over one of the columns;
- Fabricated either from steel, specifically the floating jacket or space-frame concept with this being the more common, or from concrete;
- Incorporating heave suppression discs, at the base of the columns;
- Incorporating variable numbers and configurations of catenary mooring lines.

This concept can also potentially be deployed in the shallowest waters, arguably down to 25 m for small wind turbines in benign wave climates; however, this does cause the design of the catenary mooring to become challenging. Contrary to instinctive impressions, it is hardest to design catenary moorings in the shallowest waters, since the lines become taut with relatively little horizontal movement of the floater.

A large part of this structure lies at the water's surface, inevitably leading to greater structural loads and higher amplitudes of motion. The primary columns provide the buoyancy and reactive moments to the wind turbine thrust, hence need

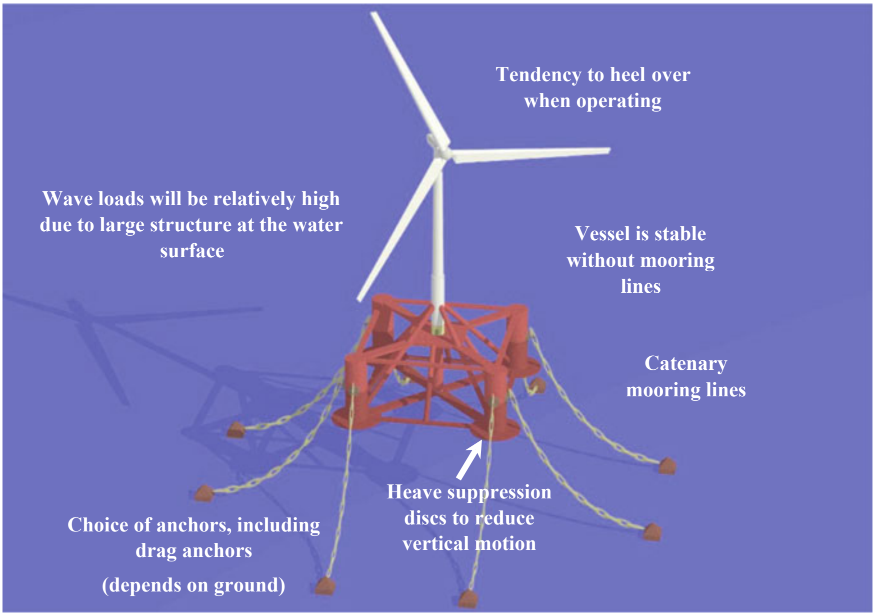


Fig. 7 Floating jacket—summary of the technical details

to be substantial. Elsewhere in the platform, slender lattice structural members for bracing will reduce wave loads.

An alternative configuration is with a concrete structure; this will have a significant impact on the motion response, hence requiring a full redesign including optimisation of the floater.

Motion response can be mitigated by applying advanced design features to the structure, including of relevance to semi-submersible platforms:

- Positioning of the largest structural members so that wave loading is out-of-phase for the predominant and design critical waves at the site; this might involve a site specific design;
- Introducing heave-damping plates, i.e. at the base of the primary columns; wave motion reduces rapidly with water depth and such plates synchronise the vessel movement towards the lower amplitudes of wave motion at depth;
- Incorporating a moon-pool; this is an unusual and rarely utilised device but in theory changes natural frequencies and provides damping; it requires a sophisticated approach for the modelling, diffraction will be insufficient and advanced CFD will be required, together with extensive tank test trials;
- Structural geometry can also provide damping, such as shape of the structure and sharp edges.

Similar to bottom-mounted offshore wind turbine jacket foundations, the fabrication effort required to build a steel semi-submersible is immense and requires advanced assembly techniques. Cost of fabrication will greatly exceed the cost of material, hence a fabrication-optimised design will be required, as opposed to focusing design efforts on saving steel tonnage. The obvious approach would be to build on any techniques currently being developed by the offshore wind industry for bottom-mounted jackets.

Similarly, the manufacturing methods for concrete semi-submersibles will be critical to achieving attractive cost levels. The same challenges that currently face concrete offshore wind GBS foundations apply, in terms of finding suitable sites and the costs of setting up the assembly facilities. It should be appreciated that the lack of suitable floating crane vessels for GBS foundations will not affect floating foundations (noting that self-buoyant GBS foundation designs would also avoid the need for an installation vessel).

Like the spar, this concept can be assembled from proven subsystems however the initial size and hence cost of the concept can appear prohibitive. A successful implementation of floating jackets will require optimisation of the complete system, for example in terms of the number of columns (three appears to have the edge), minimising wave induced motion (through heave plates and semi-taut moorings) as well as other more original solutions being proposed.

1.5 Summary of Support Structure Options

To summarise this section, a few final remarks on floating platforms for offshore wind turbines can be made:

- There is a wide range of floating foundation concepts that can be used for offshore windfarms;
  - foundation concepts can be classified according to three broad types, where the geometry of the structure is driven by how the platform counters the overturning moment generated by the wind turbine rotor thrust force;
  - the three foundation classes are:

    firstly spar buoys, long slender vertical structures where ballast counters the turbine thrust,
    secondly semi-submersibles, shallow and wide lattice-type structures floating on the surface, where distributed buoyancy counters the turbine thrust, and
    thirdly tension-buoyant platforms, horizontal structure held below the surface by taut vertical mooring lines, where the tension in the mooring lines counters the turbine thrust.

- Technically viable water depths start at sites where monopiles and jackets are currently being deployed, however the great advantage of floating foundations are to allow much deeper sites to be exploited, the most attractive being those with good wind resources and which are suitably close to both the shore and a suitable grid connection point, as well as a local demand for power;

- Suitable integrated wind turbine-floating-platform software is available, able to model critical aspects of both the wind turbine and the floater, in particular the wind turbine control and the slack mooring line dynamics; validation against demonstration units will increase confidence in design capabilities and allow further optimisation, thus saving weight and cost (for further information on software packages available to model FOWTs, see Sect. 5 in chapter "Modelling of Floating Offshore Wind Technologies");
- Several demonstration units are in the water in Europe and Japan, with the wind turbines performing well under characteristic floating conditions: i.e. that long-period motion.

2 Wind Turbine Options

Maurizio Collu

This section presents a high level comparison of the wind turbine options considered for offshore floating wind turbines. In particular, it considers Horizontal Axis Wind Turbines (HAWTs) and Vertical Axis Wind Turbines (VAWTs), comparing their main characteristics in view of the very different nature of the offshore metocean conditions.

The onshore wind industry has reached a relatively mature level, and a large majority of large scale wind turbines share the same configuration: horizontal axis of rotation, three blades, upwind, variable-speed, variable blade pitch (with feathering capability). This has been the result of several decades of research and development, and originally several configurations had been considered, including HAWT with a different number of blades, but also VAWT configurations. For example, Éole (shown in Fig. 8) is the largest VAWT built, with a height of 110 m and a rated power of 3.8 MW. It had been operating for six years (1986–1993), with availability equal to 94 %. The conventional HAWT design eventually emerged as the optimum techno-economic trade-off for the onshore large scale wind market (Tangler 2000).

The same evolutionary process did not take place for the offshore wind market, substituted by a *marinisation* of the configurations used for the onshore market. It has been implicitly assumed that, despite the very different environmental conditions of an offshore environment, the optimum configuration for the wind turbine is the same: the conventional three bladed, upwind, horizontal axis wind turbine. This has been implicitly assumed not only for the seabed-fixed offshore wind turbine configurations, but also for the proposed floating systems. The National Renewable Energy Laboratory (NREL) proposed a reference wind turbine to be used to compare different fixed and floating support structures for offshore wind turbines

Fig. 8 Éole, the largest VAWT, 110 m height, 60 m diameter, Cap-Chat, Québec. *Source* Spiritrock4u at en. wikipedia

(Jonkman and Butterfield 2009). It is widely used, and the configuration is basically the same as a conventional onshore large wind turbine. But recently there has been a resurgence of interest for VAWT (Shires 2013; Borg et al. 2014).

In the following sections, HAWT and VAWT configurations are compared and contrasted highlighting some of the key aspects in terms of advantages and disadvantages for a floating wind turbine application, referring not only to the R&D state-of-the-art, but also to recent and ongoing projects.

2.1 HAWT and VAWT: High Level Comparison

Aerodynamics

The aerodynamics of HAWT and VAWT are substantially different, and in this section only the main characteristics of both, which can simply illustrate the resultant differences in aerodynamic efficiency, are considered. For more details on the aerodynamics of VAWT and its modelling see Borg et al. (2014), while for HAWT further details are presented in Sect. 1 in Chapter "Modelling of Floating Offshore Wind Technologies".

Assuming a uniform and steady wind field (simplified conditions), it can be easily seen that a section of a blade of a VAWT and of a HAWT operate in very different flow regimes. For a HAWT, each blade section operates at a constant angle of attack, and therefore it can be designed, for a given RPM, to operate at optimum conditions (i.e. optimum angle of attack to generate the highest torque). As a consequence, the aerodynamic forces acting on the HAWT rotor are constant, including the torque produced by the rotor, transmitted eventually to the generator to produce electric power.

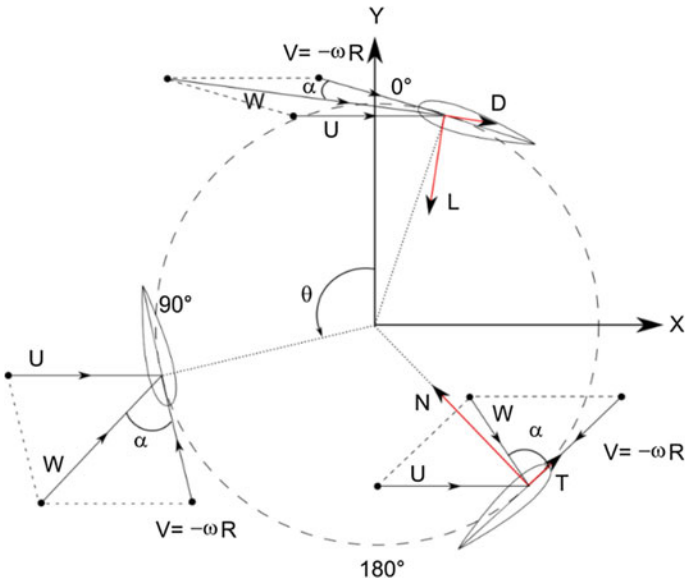


Fig. 9 Illustration of the variation of the angle of attack (**α**) with the blade angular position (***θ***) for a VAWT section (***U*** = wind speed, ***V*** = tangential speed due to the angular rotation velocity ***ω***, ***R*** = radius of the wind turbine, ***W*** = vectorial wind speed resultant) (Jamieson 2011)

Differently, for the same conditions, each section of a VAWT blade operates at an angle varying with the blade angular position, as illustrated in Fig. 9, and therefore the aerodynamic forces acting on this wind turbine are oscillatory in nature. For example, in Fig. 10, it can be seen the difference between the constant (not taking into account the effect of the tower) thrust force acting at rated power on a 5 MW HAWT versus the oscillating thrust force acting on a 5 MW VAWT (Borg and Collu 2015). This implies that the VAWT blade section cannot operate at the optimum angle of attack over the whole cycle, and therefore from this point of view the aerodynamics of VAWTs is inherently inferior to that of HAWTs. Recently there have been a number of projects trying to overcome this weakness adopting periodically pitching blades, even if it is still unclear if the added costs associated with the additional necessary systems and the lower reliability is paid off by the higher aerodynamic efficiency: the simplicity of stall-regulated VAWTs is often claimed as one of its major benefit. Nonetheless, in this case the theoretical power coefficient limit for VAWTs would be the same Betz limit (C_p < 16/27) that applies for HAWTs, and some authors (Newman 1986) even suggest a higher value if in the aerodynamic analysis the *upwind* blades (the blades in the angular positions 0° < θ < 180°) and the *downwind blades* (180° < θ < 360°) are considered acting on two different actuator disc, for which it can be derived an equivalent Betz limit of C_p = 16/25.

The power coefficient is the percentage of kinetic power in the wind that is harvested by the wind turbine, and can be considered as the reference measure of

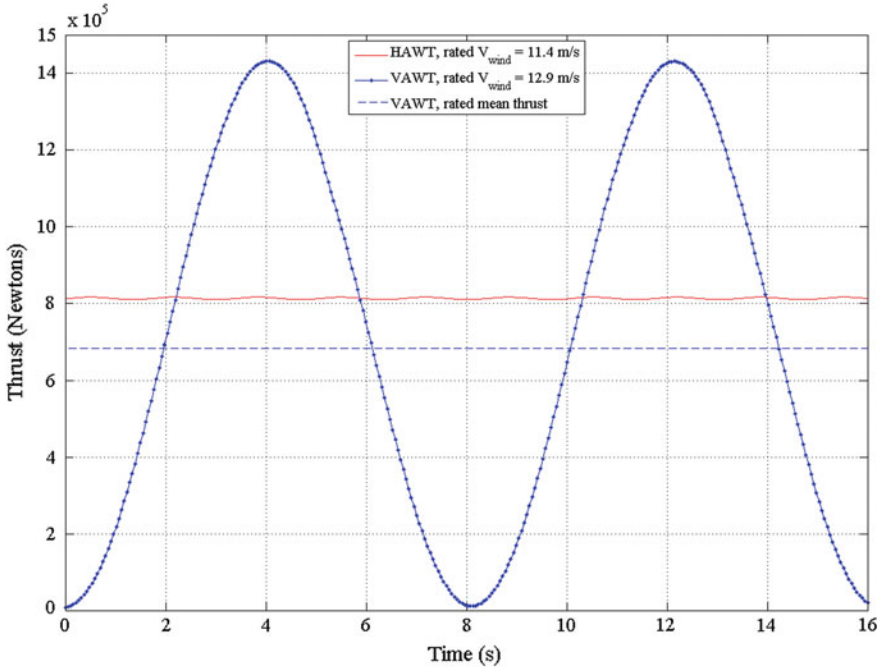


Fig. 10 Comparison between the thrust forces acting on a 5 MW HAWT and a 5 MW VAWT (Borg and Collu 2015)

the wind turbine aerodynamic efficiency. In Fig. 11 are compared the power coefficients of different typologies of wind turbine against the tip speed ratio λ, defined as the ratio between the tangential speed of the rotor blades and the undisturbed wind velocity. For modern three bladed, variable pitch, variable rotational speed, upwind HAWTs, the maximum C_p can reach values around 0.5 and above (Hau 2013), while for VAWT (fixed pitch blades) the maximum C_p demonstrated is around 0.4.

Considering their lower power coefficient, one may ask what is the reason behind the recent resurgence in interest in VAWTs: one key aspect is the inclining moment generated by the wind turbine, especially when considering floating support structures. When a wind turbine, HAWT or VAWT, is operating, it will be subject to a thrust force, parallel and in the same direction of the wind. This thrust force can be considered to act at a point, the centre of thrust pressure (C_T). In a recent work, Borg and Collu compared the dynamics of a reference 5 MW offshore HAWT against a 5 MW offshore VAWT concept (Borg and Collu 2015), and in Fig. 12 is shown the comparison between the two C_T positions. The inclining moment acting on the wind turbine and transmitted to the support structure can be estimated by multiplying the thrust force by the arm equal to the distance between the C_T and the point where the thrust force is counteracted (for a floating wind

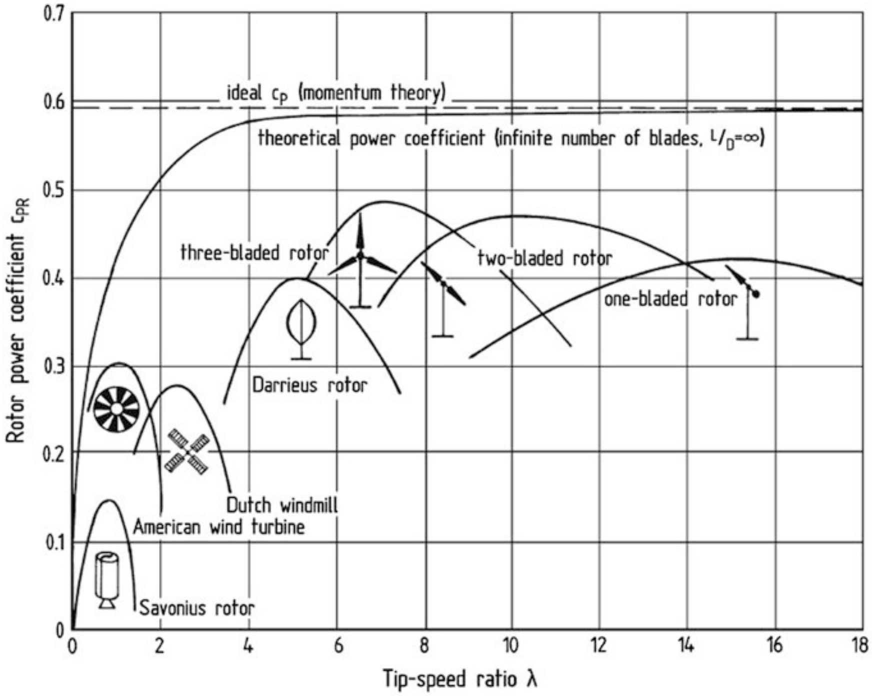


Fig. 11 Wind turbines' power coefficients vs. tip-speed ratio (Hau 2013)

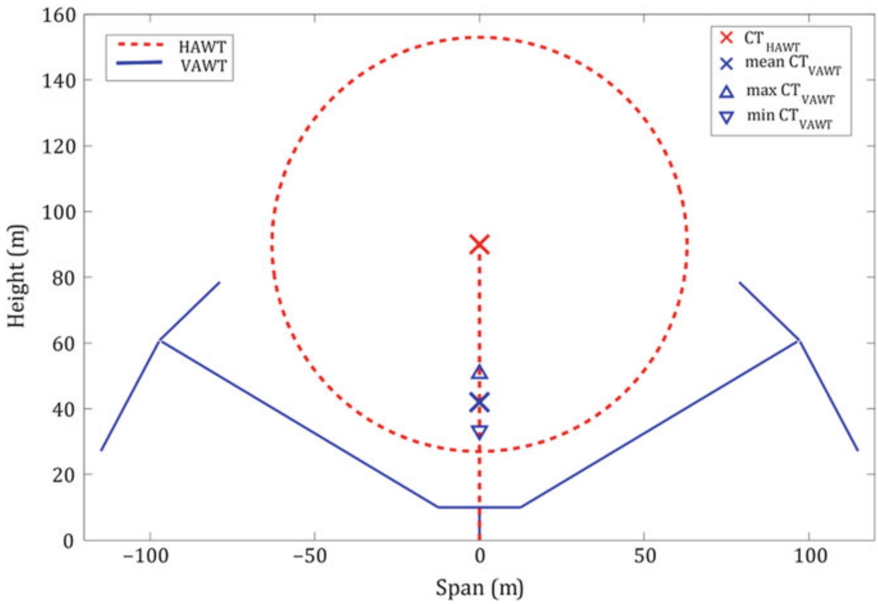


Fig. 12 Front view schematic of HAWT (NREL 5 MW) and VAWT (NOVA 5 MW), with the centre of thrust pressure, C_T, indicated. Note that the height of the VAWT C_T varies as the turbine rotates, with maximum and minimum values indicated (Borg and Collu 2015)

turbine, this typically coincides with the mooring lines attachment point). As illustrated in Fig. 10, the average VAWT thrust for this configuration, at rated wind speed, is slightly lower than the HAWT thrust force but, similarly to the other aerodynamic forces acting on the VAWT, it oscillates around this value, up to thrust forces almost double than the HAWT one. Nonetheless, the position of the VAWT C_T can be much lower than the HAWT C_T, resulting in a final VAWT inclining moment much lower than the HAWT inclining moment, as illustrated in Fig. 13. As illustrated in more detail in the following sub-section *static stability*, since the VAWT has a lower inclining moment for the same rated power, the floating support structure has the potential to be smaller and, consequently, potentially less expensive. It has to be noted that this effect depends on the VAWT configuration, and for the V-shaped VAWT considered in the Borg and Collu (2015) study this effect is particularly enhanced. Nonetheless, it is a good example to illustrate one of the potential advantages of VAWT configurations for offshore floating applications.

Another important aspect to be considered is the aerodynamic behaviour of the wind turbine when operating in *skewed flow* conditions. For HAWTs, the optimum condition is when the wind direction is perpendicular to the rotor disc, and therefore parallel to the axis of rotation. In order to satisfy this condition, when the wind direction is parallel to the ground but not perpendicular to the rotor disc, modern HAWTs are equipped with a yaw control system (NB. due to the axisymmetric

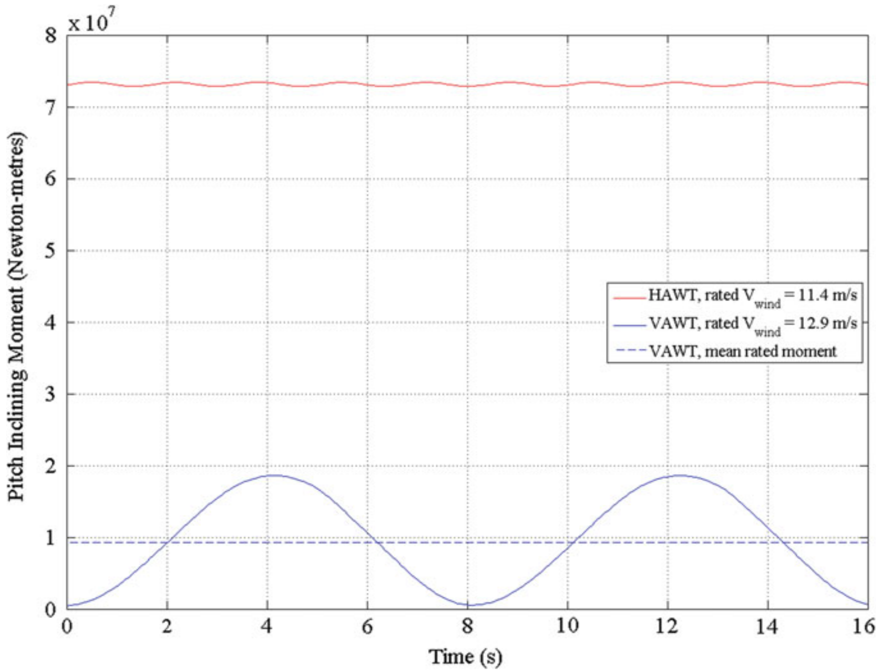


Fig. 13 VAWT and HAWT rotor inclining moments at the relative rated wind speeds (Borg and Collu 2015)

configuration of VAWTs, they are insensitive to the yaw angle of the wind, so no yaw control system is required). When a floating support structure is considered, due to the inclining moment transmitted by the rotor to the support structure, and due to the action of the wave loads, the wind turbine can be operating inclined toward the wind or away from the wind, in a so-called *skewed flow* condition. Theoretical studies and experimental measurements have shown that the skewed flow condition is detrimental for HAWTs (Tongchitpakdee et al. 2005), while for some VAWT configurations it can not only be less detrimental, but even beneficial. If H-VAWT configurations are considered, as shown by theoretical and experimental studies (Mertens et al. 2003; Ferreira et al. 2006), the coefficient of power in skewed conditions can be higher than the coefficient of power in upright conditions (i.e. for a VAWT with axis of rotation perpendicular to the wind direction): the main reason proposed to justify this phenomenon is that when the wind turbine is inclined toward the wind or away from the wind, a fraction of the blade/s in the downwind cycle ($180° < \theta < 360°$ in Fig. 9) is exposed to a wind flow no longer disturbed by the blade/s in the upwind cycle, and therefore can extract more energy from it, as it can be seen from Fig. 14. In an offshore environment, floating wind turbine systems will be oscillating most of the time, and therefore the wind turbine will be very often operating in a skewed flow condition, making the H-VAWT configuration more suitable from this point of view.

Drive Train

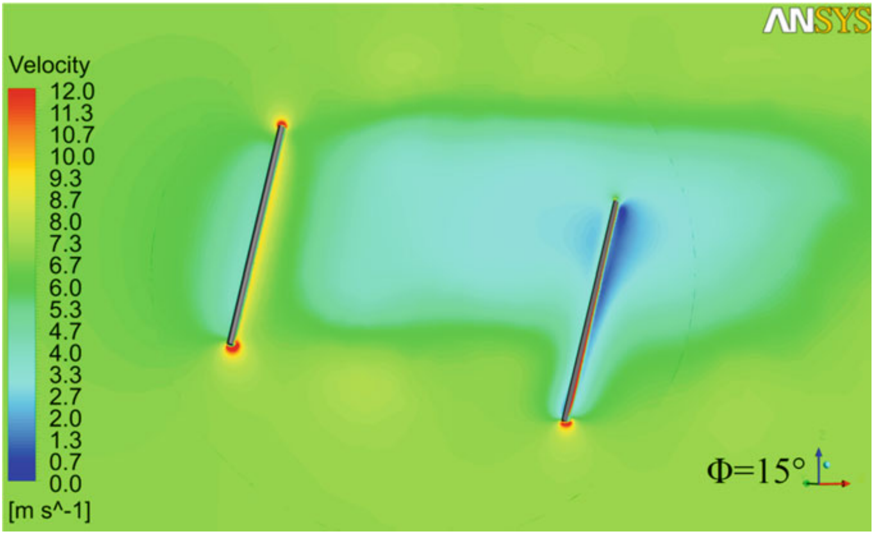


Fig. 14 Velocity field for an inclined H-VAWT, angle of inclination $\boldsymbol{\Phi}$ = 15°, positive if away from the wind, wind direction *left* to *right*, parallel to $\boldsymbol{x}$-axis. The downwind blade, on the right, is not completely in the lower speed region (*blue*) due to the upwind blade, and therefore the bottom part is exposed to higher wind speeds (Orlandi et al. 2015)

A consequence of the different aerodynamics of VAWTs with respect to HAWTs is that, in general, the optimum tip-speed ratio λ for VAWTs is lower than the one for HAWTs (Jamieson 2011), as also illustrated by Fig. 11. Since the power generated by a wind turbine can be derived as:

$$P = T\omega \tag{1}$$

where T is the torque and ω is the rotational speed, it can be seen that, for the same rated power P, lowering ω will augment T.

Due to the previous consideration, VAWTs tend to have lower rotational speeds than HAWTs, and therefore the average torque transmitted is higher for the same output power. As for the other aerodynamic forces, also the torque for a VAWT is oscillatory in nature, and this means that the maximum torque will be even higher than the average torque. Since the driving parameter for the weight and the cost of a drive train is the maximum torque, for the same rated power, a typical VAWT needs a heavier and costlier drive train. This challenge can be reduced if the height-to-radius VAWT aspect ratio is increased: in fact, for the same λ, ω is augmented, and therefore the maximum torque is diminished, with beneficial effects on the weight and cost of the drive train.

The oscillating nature of the torque for VAWTs, compared to the (at constant wind and rotational speed of the rotor) constant torque of HAWTs, constitutes a disadvantage for the VAWT configuration. For example, while for HAWTs the drive turbine systems can be optimised for the rated torque, linked to the rated power, for VAWTs the design need to take into account a wide oscillatory variation of the torque.

Other aspects also need to be taken into account. For offshore wind turbines in general, and for floating wind turbines in particular, the position of the drive train assembly is an important aspect of the design, and one where VAWT design may claim some advantages over the HAWT counterpart. The most suitable location of the drive train for a HAWT is the nacelle, on top of the tower: this can be at around 100 m above the waterline level for modern 5 MW + HAWTs, and the nacelle can weight around 400 t. These heights and weights can pose serious challenges in terms of installation and maintenance, impacting on the costs of these operations and on the availability of the wind turbine. Furthermore, they drive the structural design of the tower, which needs to withstand such large bending moments. In addition to this, the high position shifts the centre of gravity (CoG) of the whole structure upward, having a negative effect on the stability of floating wind turbines (see the following sub-section *static stability*).

One of the potential advantages of VAWTs with respect to HAWTs is the possibility to transmit the torque along the rotational axis down to the ground level (seawater level), and therefore have all the main drive train systems at this level. This not only facilitates the installation and the maintenance of these systems, since it is much simpler, especially in an offshore environment, to have access to a system at ground level rather than at a height $\sim$100 m, but will also lower the CoG of the whole system, with a beneficial effect on the overall stability. Furthermore, being at ground level, upscaling the drive train assembly for higher rated powers will have a lower impact on the wind turbine structure: for a HAWT, the drive train upscaling has an impact on the structural design of the tower sustaining the rotor and the drive train. On the other hand, to transmit the torque down to the ground level it is necessary to adopt a VAWT tower-less design, such the V-shaped VAWT (e.g. the Energy Technologies Institute (ETI) NOVA project), or a rotating tower approach, like in the FP7 EU-funded DeepWind project, or to have a shaft able to transmit the aerodynamic torque down to the basement, where the drive train is located. For these reasons, some of the VAWT designs have their drive train on top of the tower similarly to the HAWT.

Static Stability

Referring to Fig. 15, for a floating wind turbine system, under the small angle of inclination approximation, the equilibrium between the inclining moment

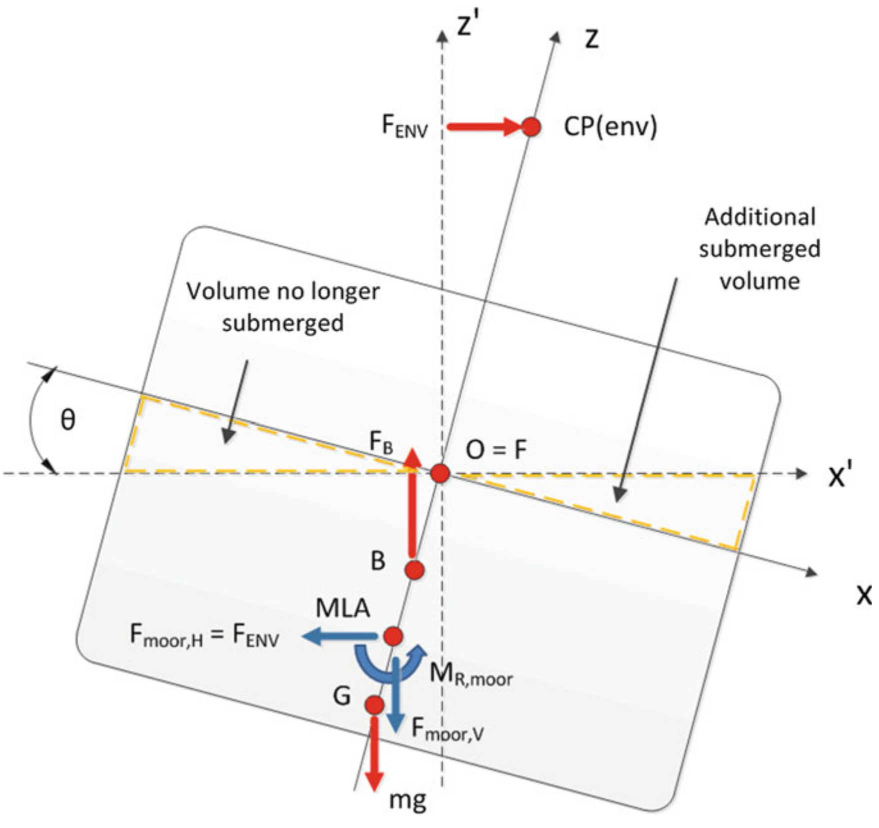


Fig. 15 Diagram of forces and moments acting on a floating wind turbine system, longitudinal plane (pitch degree of freedom/rotations around ***y***-axis, ***x***-axis aligned with wind speed direction) (Collu and Borg 2016)

transmitted by the wind turbine and the restoring moment generated by the floating support structure can be written as (Borg and Collu 2015):

$$M_I = M_R \tag{2}$$

$$M_I = F_{env}\left(z_{CP(env)} - z_{MLA}\right)\cos\theta \approx T(z_{CT} - z_{MLA}) \tag{3}$$

$$M_R = \left(\rho g I_x + F_B z_{CB} - mg z_{CG} + C_{55,moor}\right)\theta = C_{55,tot}\theta \tag{4}$$

where $C_{55,moor}$ (Nm/rad) = rotational stiffness provided by the mooring system (e.g. TLP); F_B (N) = buoyancy force; F_{env} (N) = sum of environmental forces (wind, wave, currents) along the x-axis (in the present simplified analysis, this is represented by the aerodynamic thrust force T only); g (m/s^2) = gravitational acceleration; I_x (m^4) = second moment of waterplane area with respect to the y-axis; m (kg) = total mass of the floating wind turbine system; M_I (Nm) = inclining moment around y-axis (wind parallel to axis y, z perpendicular to x and y, positive upward; M_R (Nm) = restoring moment around axis y; $z_{CP(env)}$ (m) = vertical position of the centre of pressure of environmental forces, defined as the point on which the sum of the environmental forces (in the present simplified analysis, it coincides with the vertical position of the centre of aerodynamic thrust pressure, z_{CT}); z_{CG} (m) = centre of gravity of the whole floating wind turbine system; z_{MLA} (m) = centre of mooring line action, i.e. the intersection of the line of action of the horizontal component of the mooring force with the z axis; θ (rad) = inclination angle, rotation around the y-axis; ρ (kg/m^3) = seawater density.

In the design phase of a floating wind turbine system, one of the requirements is to limit the maximum angle of inclination (θ_{max}) of the whole system, in order to limit the loss of power produced due to the skewed flow condition, as previously mentioned. This can be translated in a requirement to have a minimum rotational stiffness C_{55}, or:

$$C_{55,\min} = \frac{M_I}{\theta_{\max}} \tag{5}$$

In general, the higher the rotational stiffness required, the more expensive the floating support structure will be, and therefore the aim is to reduce it as much as possible. With regard to θ_{max}, the aerodynamic performances of floating HAWT and VAWT systems operating with their axis of rotation not parallel (HAWT) or perpendicular (VAWT) to the wind direction is still a relatively unexplored research field. According to Zambrano et al. (2006), a maximum mean pitch/roll angle of 5° plus ±15° of dynamic amplitude should be imposed. Referring to Eq. (3), as previously mentioned in the section on aerodynamics, for the same rated power, the inclining moment of a VAWT configuration can be much smaller than the one of an HAWT configuration, and this has a beneficial effect since it reduces $C_{55,min}$ with a positive impact on the final cost of the floating support structure.

Referring to Eq. (4), it can be seen as a higher position of the CoG (higher z_{CG}) has a detrimental effect on the restoring capability of the floating support structure. In order to compensate this destabilising effect, the other terms composing the total restoring moment should be augmented, augmenting I_x (i.e. for a Trifloater floating support structure, it means larger columns and/or a larger distance between the columns), and/or augmenting the stiffness provided by the mooring system: both solutions will result in a costlier floating support structure. Depending on the VAWT configuration, for the same power, a lower CoG can be achieved, especially if the drive train systems are located at ground (seawater) level.

2.1.1 Maturity of the Technology

The majority of the state-of-the-art offshore floating wind turbines prototypes, some of which are illustrated in Chap. 6, have adopted HAWTs. These wind turbines, due to their superiority for the onshore market, have been intensively studied, analysed, developed and optimised over the past decades, and the design has now converged toward relatively few options, with the so-called *Danish design*, the three-bladed, upwind, variable pitch, variable rpm, horizontal axis wind turbine, having the lion share of the market. On the other hand, despite major research and development efforts on VAWTs mainly in Canada, in USA, and in UK during the 1980s and 1990s, and even taking into account the recent resurgence of interest in VAWT for the offshore wind market over the past years (Shires 2013; Borg et al. 2014), VAWT technology is still lagging behind in terms of maturity with respect to HAWT.

In Chap. "State-of-the-Art" an up-to-date overview of current floating HAWT projects are presented. For completion a brief description of some of the main floating VAWT projects is given below, together with some references on where to find more information.

The DeepWind Project

The DeepWind project had been funded by the European Union through the Framework Programme 7 (FP7), and started on the 1st of October 2010, with a length of 4 years. The consortium consisted of twelve partners, including several universities and some major offshore wind companies, as well as research institutes, coordinated by the Technical University of Denmark (DTU). The aim of the project was to develop a novel offshore floating VAWT concept, specific for deep water sites, which could substantially reduce the cost of electricity of floating offshore wind energy (Paulsen et al. 2014). The concept was based on a Darrieus type rotor, with the main novelty being the fact that it was installed on a rotating spar platform, moored to the seabed through torque arms and catenary mooring lines. The project produced a 1 kW prototype, which has been manufactured and experimentally tried in real sea conditions. This prototype has been used for refining the conceptual and preliminary design of the 5 MW floating VAWT concept. A comprehensive set of analytical and numerical analyses has been carried out in order to not only estimate the power production, but also to evaluate the loads acting on the system and to perform a first structural design of the main components. The drive train system is positioned underwater, at the bottom of the spar platform (this is another novelty of the project), with the main aim of substantially reducing the inclining moment acting on the bearing system of the wind turbine. This has been recognised as one of the main challenges for large VAWTs, requiring large bearing system not currently available at commercial level, and therefore significantly impacting on the final cost of electricity. The project has also delivered a conceptual design of a 20 MW floating VAWT, in order to show the potential to further reduce the cost of offshore floating wind electricity.

Several economic analyses have been conducted in order to estimate the Levelised Cost of Electricity (LCOE),[1] showing that for a 500 MW wind farm, considering a lifetime of 25 years, the estimated reference cost would be around 63 €/MWh, with a lower estimate of 59€/MWh and an upper estimate of 75€/MWh (Paulsen et al. 2015). To have a comparison, in the United Kingdom from the first offshore wind farms ($\sim$2000) until 2011, the LCOE has been increasing, levelling out at around 175€/MWh during the period 2011–13 (The Crown Estate 2012).

The main outcomes of the project are summarised by Paulsen et al. (2015), and the main numerical simulation challenges have been illustrated by Verelst et al. (2015).

The Nénuphar-Led VAWT Project

In 2009, with the first project VERTIFLOAT, the French start-up company Nenuphar led the development and manufacturing of the first 35 kW onshore prototype. This project seems to be the first step toward the development of the first offshore floating VAWT wind farm, through several projects co-funded by the French government, the EU and some of the big industries in the field (project VERTIWIND, project INFLOW, project VERTIMED) (IWES 2013). In May 2014, the first stage of a 2 MW onshore prototype of this VAWT configuration started to be operative, as part of the VERTIWIND project activities, and the objective is to be used as test-bed to further develop and optimise the wind turbine in view of the first floating wind turbine version of this concept.

Scalability

One of the advantages of moving wind turbines offshore is the potential to scale them up to very large rated power: in general, the larger the wind turbine, the lower will be the final cost of electricity produced. The trend toward larger wind turbines offshore has been clearly observed over the past years, from the 0.45 MW wind

[1]In simple terms, LCOE can be seen as the lifetime cost of the project, per unit of energy generated. It is defined as the sum of discounted lifetime generation costs (£) divided by the sum of discounted lifetime electricity output (MWh). Generation costs include all capital, operating, and decommissioning costs incurred by the generator/developer over the lifetime of the project, including transmission costs (The Crown Estate 2012).

turbines adopted for the world's first offshore wind farm, Vindeby, in Denmark, to the Westermost Rough wind farm, under construction (2015) in the UK, adopting 35 Siemens SWT-6.0-154 (6 MW).

With the offshore wind farm moving to further and deeper sites, the floating wind turbine solution is becoming more and more economically viable, but even considering the lower costs of a floating solution rather than a fixed support structure, the overall costs are likely to increase. This will reinforce even more the need to accelerate the development of bigger, higher rated power wind turbines.

Comparing HAWTs and VAWTs from the upscaling potential point of view, Clare and Mays observed in 1989 that (Clare and Mays 1989):

> The cyclically varying gravity stresses of a HAWT become progressively more dominant as the overall turbine size is increased and could limit the size to which a horizontal axis rotor can be economically constructed. Although the blades of a VAWT experience fluctuating aerodynamic loads, the stresses that result from these do not increase with the size of the wind turbine and gravity stresses do not fluctuate. Consequently, there is potential for development of VAWTs to sizes significantly larger than HAWTs and for improvement in the economics of offshore wind energy systems

It has to be observed that the previous statement is certainly a valid point, but it is difficult to estimate what would be the related rated power limit for HAWT. At the moment (2015), there are already 7 MW offshore HAWT commercially available (e.g. Siemens SWT-7.0-154), and 8 MW ones close to commercial maturity (e.g. Vestas V164-8.0 MW), while there are several projects looking at 10 MW and beyond HAWTs (Project HiPRWind). In particular, the EU funded FP6 project UpWind (2006–2011) and its successor, the EU funded FP7 project InnWind.EU (2012–2017) are looking at innovative solutions for offshore HAWTs from 10 to 20 MW. In the final report of the project UpWind (UpWind Consortium 2011) it is mentioned that:

> UpWind did not seek the optimal wind turbine size, but investigated the limits of upscaling, up to, approximately, 20 MW/250 m rotor diameter

and it is claimed that

> UpWind demonstrates that a 20 MW design is feasible. No significant problems have been found when upscaling wind turbines to that scale, provided some key innovations are developed and integrated. These innovations come with extra cost, and the cost /benefit ratio depends on a complex set of parameters.

Nonetheless, in principle VAWTs have the potential to be scaled up to higher rated powers, with the potential to further lower the cost of offshore wind electricity. In the UK, the Energy Technology Institute (ETI) funded a 1 year and half project, NOVA (Collu et al. 2014), aimed to demonstrate the feasibility of a large VAWT. Based on a novel V-shaped VAWT configuration, having as a main advantage the minimisation of the inclining moment, and therefore enhancing its suitability for floating support structures, the project investigated a 5 MW and a 10 MW offshore VAWT solution, from the conceptual and preliminary design to the evaluation of the final LCOE.

2.2 Summary of Wind Turbine Options

As regard the onshore wind industry, during the 1980s the need to lower the cost of energy led to the demise of many VAWT concepts, perceived as less cost effective compared with HAWTs (Tangler 2000). Attracted mainly by the higher and more consistent winds, the lower visual impact, and the upscaling potential, the wind industry has progressively moved toward offshore sites: at first near-shore, in relatively shallow waters, and now further offshore, in deeper water sites. At which depth a floating wind turbine becomes more cost effective than a fixed one? The debate is still open, but eventually in the range between 50 and 100 m it is very probable that a floating wind turbine is economically advantageous with respect to a fixed to seabed solution.

If the offshore, deep water environmental conditions are compared to the onshore environmental conditions, where the HAWT concepts have competed and prevailed against the VAWT concepts, it appears immediately evident that they are substantially different. Therefore, the question arises: is the HAWT configuration the most suitable for this novel environmental conditions still, or do we need to take a step back and compare again the HAWT configurations to some of the alternative concepts initially considered even onshore? The fact that the HAWTs are being adopted also for the first floating prototypes is the result of a systematic and detailed design space investigation, comparing alternative concepts, or is more due to a legacy from the onshore wind industry?

Even if inherently less efficient from an aerodynamics point of view, VAWTs can have, if compared to a HAWT with the same rated power, a substantially lower inclining moment, and this advantage can be translated into a smaller and cheaper floating support structure, lowering the final cost of electricity. Furthermore, while for a HAWT configuration there is a loss of aerodynamic efficiency in skewed flow conditions, a condition very common for floating wind turbines due to the wave loads, for certain VAWT configurations (H-VAWT) it seems not only that these conditions are not detrimental, but also beneficial.

From a drive train system point of view, due to the lower rotational speed VAWTs need larger, heavier and therefore costlier drive train systems than HAWTs. Nonetheless, while for HAWTs the drive train systems are usually located in the nacelle, on top of the tower, for VAWTs there is the possibility to locate the drive train assembly at ground (seawater line) level, with advantages in terms of installation, accessibility and maintenance, as well as upscaling potential. Having a drive train system at ground level also lowers the vertical position of the CoG of the whole system, that is beneficial for its stability. Again, together with the lower inclining moment, the enhanced stability can be instead used toward a smaller, less costly floating support structure, lowering the final cost of the offshore wind electricity.

In terms of technological and economic maturity, VAWTs are still lagging behind HAWTs, and need to be further investigated before determining if their potential advantages can be implemented at a practical level. Recently there have been a number of projects co-funded by the industry and various national and international governments, aimed at pushing forward the Technology Readiness Level (TRL) of floating VAWT technology: these will hopefully help in assessing their potential. Due to inherent limits of HAWTs configuration, there are some potential barrier to their further upscaling beyond 15–20 MW, and VAWT could eventually emerge as economically more viable for very large powers (15–20 MW +), as they do not suffer from the same limitations.

To conclude, while for the onshore and near-shore wind market the wind turbine configuration options seem to be limited to a narrow set, the substantially different nature of the challenges posed by the offshore, deep water environment can reopen the design space toward a number of alternative wind turbine configurations.

3 Mooring Systems

Marco Masciola

Mooring systems are the facilitators that allow floating structures to be used in deep waters where conventional jacket foundations are economically prohibitive or technically challenging. In combination with the platform buoyancy, mooring lines emulate the role of the tower substructure to maintain the position and orientation of the wind turbine. It is the goal of the designer to implement a mooring with the durability to resist external forces, yet exhibit stiffness properties for the FOWT platform to operate outside of the wave excitation frequencies. Many design variables help fulfil the goal, though the design process begins with a set of constraints.

Converging on a mooring system radial footprint, anchor type, and line properties is an iterative process. The design process begins with anchor selection based on a soil's holding capacity, which leads to the number of anchors required to oppose the total environmental forces. The total required anchor holding capacity is balanced against the external forces applied on the FOWT. The total anchor holding capacity should be sufficient to oppose the design environment loads. This holding capacity then relates to choosing a line's *minimum breaking strength*, or MBS (Ruinen and Gijs 2001; API RP 2SK 2005). Mooring properties, such as the line material, line length, and clump weights are then selected based on meeting a desired performance criterion. Simulations are subsequently run to determine if the line meets the necessary safety margins. Design iterations are performed as necessary. This synopsis describes the common design spiral for moorings.

Over the past two decades, the offshore industry has expanded into deeper waters with the introduction of synthetic fibre rope materials. FOWTs, however, usher in new and unique challenges due to a combination of shallow water depths and large wind thrust loads. This combination may lead to a need for greater mooring scope traditionally used in conventional deepwater floating production systems. Despite foreseeable challenges, the latest international standards remain applicable and are an important resource for FOWT permanent moorings. The referenced standards include:

- ISO 19901-7 (2013): Station keeping systems for floating offshore structures and mobile offshore units.
- API RP 2SK (2005): Design and Analysis of Station keeping Systems for Floating Structures.
- API RP 2SM (2014): Design, Manufacture, Installation, and Maintenance of Synthetic Fibre Ropes for Offshore Mooring.

The practices described in these standards are adopted in the forthcoming IEC 61400-3-2 international standard on floating offshore wind turbines.

3.1 Common Materials

The adopted mooring design is a compromise of many factors, including: anchor holding strength, material fatigue properties, breaking loads, seabed clearance and between other subsystems, tower and wind turbine motion limitation, special considerations for fibre ropes (such as compression fatigue, and creep characteristics), and permissible platform offset, all of which should balance to oppose environmental loads. With floating production units, the platform displacement is restricted by the risers, the conduit carrying fluid from the seafloor to the floating production unit. Although FOWTs lack risers, other factors may restrict FOWT displacement watch circles, such as bending restrictions on the power umbilical or to limit rotor waking effects to maximise capacity factor. Spacing between adjacent units is another factor the FOWT system may need to contend with for damaged line conditions.

A mooring line can be decomposed into several sections with different line types to improve the restoring force characteristics or system durability. Chain is commonly used on the lowest section of line closest to the seabed, not only because is exhibits excellent abrasion resistance, but also because the chain weight acts as a medium to bolster system stiffness through the action of raising mass off the seafloor. Wire rope is an alternative to chain exhibiting similar stiffness and weight characteristics, but with improved shock absorption properties. The cross-sectional strand pattern can affect strength by a significant degree between two steel ropes with equal nominal diameters. A third line material, known as synthetic fibre rope, has emerged in recent years allowing deep water to be reachable. Although polyester ropes are recommended for permanent installations (API RP 2SK 2005), other materials such as aramid and high modulus polyethylene (HMPE), show promise for future applications. Figure 16 compares Young's modulus for various rope types that have been studied for permanent moorings.

A mooring system may be comprised of a combination of the following components:

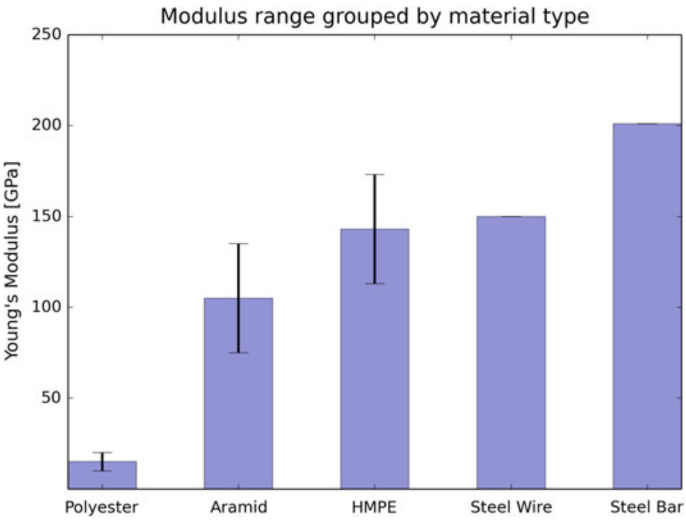


Fig. 16 Average Young's modulus for various materials for mooring systems. The *upper* and *lower* modulus bounds are given. Material properties are derived from Ayers and Renzi (2010)

- Mooring line
  - Chain
  - Wire rope
  - Fibre (synthetic) rope
- Anchor
  - Drag embedment anchor
  - Plate anchor
  - Suction pile
  - Pile and screw anchor
  - Gravity anchor
- Clump weights and buoyancy modules
- Connection equipment and hardware
  - Triplate
  - Shackle
  - Splices

Power umbilical's normally do not constitute as part of the mooring system since they are not designed to enhance the station keeping characteristics, though their strength analysis may follow design guidelines for moorings and risers. None the less, their analysis is vital for global performance studies. Power umbilicals serve an analogous purpose as to the risers used in oil and gas platforms, but instead of

Table 2 Yield stress and elongation characteristics of different chain grades Values are procured from API RP 2F (1997)

Chain Grade	Yield Stress [N/m^2]	Elongation (%)
R3	410×10^6	17
R3S	490×10^6	15
R4	580×10^6	12
R4S	700×10^6	12
R5	760×10^6	12

carrying fluid, the power cable transfers electricity. As with risers, the FOWT range of motion can be restricted by bending radius limitation on the power umbilicals.

Chain and Wire-Rope

Chain is prominently used throughout the offshore industry for station keeping applications either in studlink or studless construction. Marine chain is graded according to material strength scaled by R3, R3S, R4, R4S, and R5 as described in Table 2 (API RP 2F 1997). Chain is graded to promote consistency across various manufactures and ensure that minimum strength characteristics are guaranteed. This assurance is based on industry standard qualification testing that manufacturers submit to.

The strength of steel wire rope, on the other hand, must be judged carefully and on a case-by-case basis. The strength depends on several factors ranging from the use of cathodic protection to the type of stand pattern used. Steel wire rope lifespan can range from six to 35 years. The lifetime ranges are estimated to be (API RP 2SK 2005):

- 6–8 years for 6-strand galvanised steel wire line.
- 10–17 years for spiral-galvanised strand.
  - 10–12 years without corrosion protection.
  - 15–17 years with corrosion protection.
- 20–35 years for spiral-galvanised with protective sheathing.
  - 20–25 years without corrosion protection.
  - 30–35 years with corrosion protection.

As indicated, the strand, sheathing, and corrosion protection all combine to influence the rope life span. While designing a mooring, it is common to work with the chain or rope manufacturer to ensure the simulated properties reflect real-life properties. The life span is roughly estimated based on past experiences, though in practice, routine inspections are required to monitor life cycle.

3.1.1 Fibre Rope

Over the past 20 years, fibre ropes have demonstrated versatility in permanent deep water, station keeping applications (Kwan and Bruen 1991; Flory and Banfield

Table 3 Variation of stiffness for fibre ropes. Properties are taken from Ayers and Renzi (2010)

Rope family	Intermediate stiffness	Storm stiffness	Elongation characteristic
Polyester	15 × (MBS)	30 × (MBS)	Log
Aramid	35 × (MBS)	70 × (MBS)	Log
HMPE	60 × (MBS)	90 × (MBS)	Proportional

2006). Their near-neutral buoyant properties diminish negative effects from self-weight and permit deep waters to be reached. Despite the use of polyester fibre rope in deepwater oil and gas applications, little research has been applied towards fibre ropes in shallow-water FOWT designs. Undoubtedly, fibre ropes will see increased activity as FOWTs venture into deeper waters. The transition point where fibre ropes reach economic parity with conventional chain and wire rope installations is a question of not only water depth, but also platform type (tension leg platform (TLP) versus semisubmersible versus spar), deployment time, length of line, and effect on the platform natural periods.

Weller et al. (2012) characterises the long-term durability properties of synthetic lines to propose a testing/measurement protocol for ocean energy mooing applications. The authors find tensions peak at approximately 11 % of MBS, and most load measurements remain within 3 % of MBS; this region is important for fatigue analysis (Lechat et al. 2008; Weller et al. 2012). The study shows long term potential for synthetic lines if tension magnitude can be managed, but fatigue analysis is essential, as this could be a governing case for the mooring design.

Although the study demonstrates promise for fibre ropes in the offshore renewable energy sector, it also alludes to special accommodations needed due to the unique properties synthetic material possesses. Unlike steel wire strand or chain, synthetic ropes are susceptible to non-linear elongation (creep) and variable stiffness properties. Axial stiffness depends on the rope material and load range, Table 3, also depicted in Fig. 16. Aramid and HMPE occupy a large stiffness range compared to polyester, although polyester fibre rope is a proven technology for permanent moorings. Certain fibre ropes are sensitive to loss of load, such as aramids, which can succumb to wear when compressed. Given the wide variability of material properties and strength characteristics, it is common to defer to manufacturer specifications based on qualification testing.

Fibre Rope Permanent Elongation and Non-Linear Stiffness
Fibre ropes are susceptible to permanent elongation, which results in decreased mooring stiffness. Line length increases are a natural occurrence and are inevitable with synthetic materials, and engineers must accommodate and plan for permanent elongation in the mooring design. Permanent elongation properties can vary depending on the fibre rope material. Creep properties can either be linearly proportional to time or logarithmic functions of time. Polyester fibre rope is generally preferred for permanent installations because of elongation characteristics and demonstrable track record, Fig. 17 (Huntley 2006). Load history is the primary driver affecting elongation, as synthetic ropes are aware of the previous loading

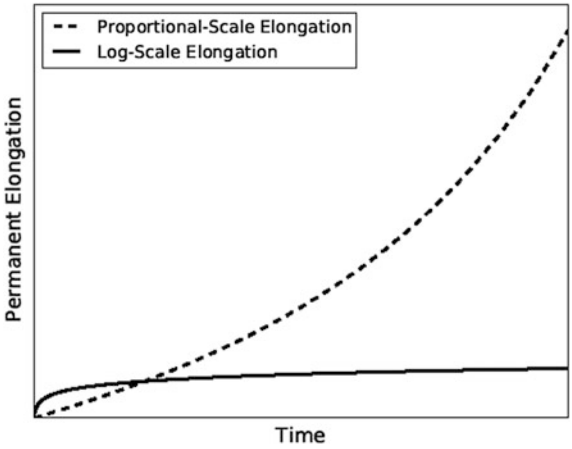


Fig. 17 Permanent elongation, or creep, results in an increase in line length relative to the original installation length. Elongation can be linearly proportional to the length of period a load is applied to the line (such as HMPE) or expressed as a logarithmic of the load history (as is the case for aramid and polyester fibre ropes)

regimes and respond by elongating as a new maximum load is encountered (Flory and Banfield 2006). Although HMPE possess proportional creep characteristics, new chemical compounds demonstrate a possibility to decrease creep coefficients to low values competing with log-proportional properties typically found in polyester ropes.

The lack of constant stiffness is a second contributor that the designer must contend with. Unlike chain and wire rope, the axial stiffness of synthetic varies depending on load amplitude (A), loading period, and average load (L). These factors can be combined to model the non-linear axial stiffness parameters (Flory 1999; Tahar and Kim 2008):

$$K = \alpha + \beta L + \gamma A \tag{6}$$

where the coefficients α, β, and γ are specified in rope qualification tests. An extra term can be included in Eq. (6) to account for permanent elongation, which is particularly important for analysis in storms. Numerical models can accommodate Eq. (6) to include the non-linear stiffness attributes (Tahar and Kim 2008). If the model is incapable of including a variable stiffness model, then the designer may have to resort to an upper and lower bound stiffness model (Wibner et al. 2003).

3.2 Composite Mooring Systems

Many applications may benefit from mixing various line properties in series to maintain adequate stiffness margins while decreasing static and dead weight loads. One such rendition is given in Fig. 18 to show the mooring profile for three lines, one of which has a composite construction. Line 1 is comprised entirely of chain, and Line 2 uses a synthetic material. A mixture of the chain and fibre rope is used in

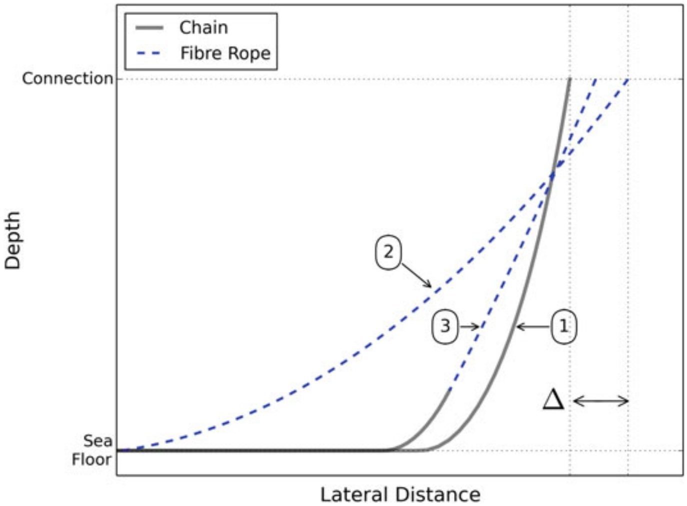


Fig. 18 The horizontal restoring force of a slack line mooring depends on the submerged weight property. This illustration demonstrates the mooring profile for three different compositions to yield equivalent mean horizontal forces at the upper terminal. The vertical force is different, since each line has a different weight. (*1*) is for chain; (*2*) is fibre rope; and (*3*) is composed of chain and fibre rope

Line 3. In this conceptual example, the fairlead for Lines 2 and 3 are extended outward until their horizontal force equals that of Line 1. One finds the all-fibre rope mooring stretches the furthest to match the restoring force of Line 1. The offset gap Δ is due to the absence of the chain weight. In effect, the presence of weight enhances the mooring stiffness. To reword this: catenary-shaped moorings derived most of their restoring stiffness from geometric non-linearities (i.e. the shape of the mooring) rather than from axial strain. The restoring force for Line 3, the line using both chain and fibre rope, lies between the two systems because a proportion of the chain weight is preserved. As more chain is lifted off the seabed, the restoring force increases by the action of raising weight.

There are repercussions to using an all-chain mooring in deep waters. Effects from self-weight eventually become a design constraint as depth increases because of growing static loads. This increasing static load may eventually require a larger chain size to meet safety factor thresholds. Under these circumstances, the benefits of fibre ropes become apparent. By placing synthetic lines in series at the upper terminal, the static loads are decreased. Note that although the horizontal force for Lines 1, 2 and 3 are equal, the vertical force static loads do not match. The applied vertical force for this statically arranged lines correlates to the submerged weight of the chain. In other words, fibre ropes can also be used as a mechanism to moderate the upper terminal vertical loads. Chain resting on the seabed also serves as a purpose of averting fibre rope soil ingress. Penetrating soil particles can exacerbate abrasion within the fibre yarn, though a protective barrier can delay or prevent premature failure (Majhi and D'Souza 2013).

3.3 Design Methodology and Applicable Standards

API RP 2SK (2005) defines the practices for designing permanent station keeping systems for floating platforms, which is the methodology adopted into ISO 19901-7 (2013). Special provisions pertaining to fibre ropes are addressed in API RP 2SM (2014). Collectively, these standards form the basis of the mooring design process accepted into the forthcoming IEC 61400-3-2 international standard for floating wind turbines.

As described in Kwan (2015), mooring design procedures are constantly evolving as new challenges are addressed with industry consensus. The first API mooring design standards were published with API RP 2P (1984) for drilling units and API RP 2FP1 (1993) for production units. Both API RP 2P and API RP 2FPI spawned the first edition of API RP 2SK (released in 1995). The latest release of API RP 2SK is currently on the third edition (API RP 2SK 2005), with the impending release of a fourth edition. Among the many differences between the first-generation mooring standard API RP 2P and the latest API RP 2SK edition, Kwan (2015) notes the following significant changes:

- Drilling units initially relied on a return period of 1-year. This is increased to larger non-exceedance probability thresholds.
- The use dynamic-based mooring simulation tools is advocated over quasi-static methodologies.
- Cyclic loading can reduce lifespan of the mooring, and fatigue analysis is introduced as an additional factor to assess.

As floating offshore wind continues to gain traction, new processes or modifications to existing procedures may come to light. A similar direction was experienced for the predecessors to API RP 2SK: API RP 2P and API RP 2FP1. Irrespective of the platform type and purpose, there are many mooring design factors that will continue to remain constant. Following the procedure in the latest mooring design standards, which are based on working stress design (WSD), the mooring system can be designed using time-domain, frequency-domain, or a combined approach (Kwan and Bruen 1991; Fitzgerald and Bergdahl 2008). Ensuring longevity and suitability of the mooring design requires the maximum tension T_{max} to remain within the allowable safety margins. The maximum tension is typically based on the maximum line terminal excursion in calm water (x_{max}).

Maximum FOWT Offset

The maximum offset is determined by combining the mean FOWT excursion from steady loads with the amplitude motion range from the time-varying cyclical loads. Steady loads include the mean rotor thrust force, wind drag from exposed surfaces, current drag, and the mean second-order drift force. Cyclical loading arises from dynamic contributions from wave-induced drag loads, frequency-dependent added mass, atmospheric turbulence, and sum-difference and sum-sum second-order wave loads.

Following the relevant standards (API RP 2SK 2005; ISO 19901-7 2013), time domain, frequency domain, and a hybrid of time and frequency domain procedures can be applied to find the maximum line tension and maximum vessel offset. A statistical distribution model is applied in the case of the time domain simulation to calculate tension values that have a very low probability of exceedance using a Weibull, Gumbel, or other extreme-value probability model (Nadarajah and Kotz 2006). The maximum offset can be calculated in the frequency domain by virtue of:

$$x_{max} = x_{mean} + \mathrm{MAX}\left(x_{dyn_1}, x_{dyn_2}\right) \tag{7}$$

$$x_{min} = x_{mean} - \mathrm{MAX}\left(x_{dyn_1}, x_{dyn_2}\right) \tag{8}$$

Each dynamic term above is determined by filtering the vessel motion frequency to find the FOWT response from 1) the wave frequency excitation range and 2) the low frequency excitation range. The mean offset, x_{mean}, is decided based on the distance the FOWT must offset for the mooring system to balance the applied environmental load.

The dynamic offset is defined as $x_{dyn_1} = \left(x_{lf_{max}} + x_{wf_{sig}}\right)$ and $x_{dyn_2} = \left(x_{wf_{max}} + x_{lf_{sig}}\right)$ with the following definitions provided:

- $x_{lf_{max}}$—maximum low-frequency motion
- $x_{lf_{sig}}$—significant low-frequency motion
- $x_{wf_{max}}$—maximum wave-frequency motion
- $x_{wf_{sig}}$—significant wave-frequency motion

The larger value of Eq. (7) or Eq. (8) is used to assess tension loads based on offsets.

Combining the mean offset x_{mean} and dynamic offset x_{dyn} to result in the maximum offset is demonstrated in Fig. 19. This offset, x_{max} is used to find the line tension based on quasi-static procedures. The mean offset can be large in FOWT systems during normal operation due to the exceptionally large thrust force in power generation mode. Although this is contingent on individual designs, the combined rotor thrust and exposed area drag force are likely to be large at two wind speeds. The first is at the rated wind speeds, where rotor thrust force is usually high. The second is at the *N*-year return period wind speeds, where the platform exposed area drag force can dominate the rotor thrust for the idling turbine. This imposes two conditions where wind drag loads are significant: one is with a low probability of exceedance (the *N*-year return period), and the second is during normal operation in power productions mode. Hence, it would not be surprising if Eq. (7)/(8) peaks during the operational load cases.

Figure 20 demonstrates the application of Eq. (7)/(8). The displacement x_{mean} is indicative of the required offset to balance the mean horizontal environmental force. This results in an average line tension magnitude of T_{mean}. With the addition of a dynamic offset x_{dyn}, the maximum line tension $T_{x_{max}}$ is achieved. Although the curve in Fig. 20 represents tension in a single line for pedagogical reasons, the collective

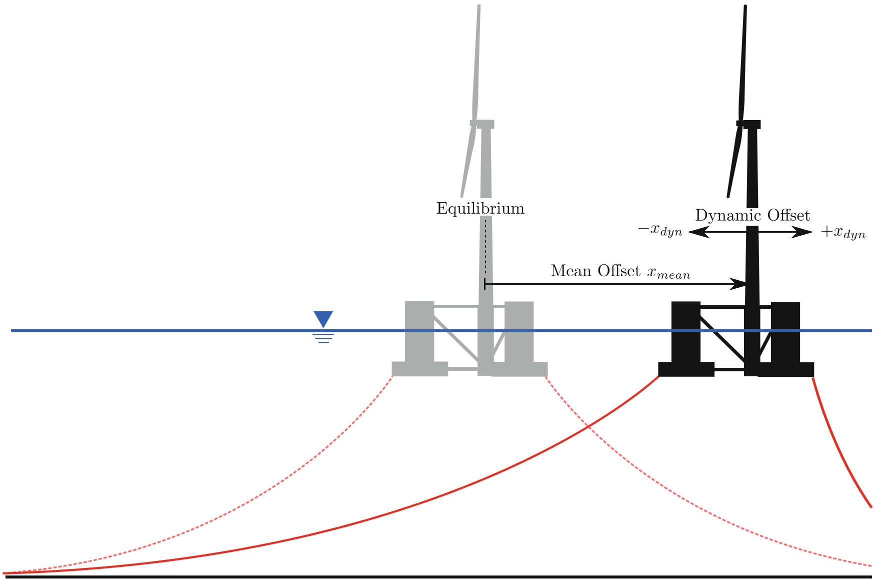


Fig. 19 Contribution of the frequency-independent mean offset $\boldsymbol{x_{mean}}$ and frequency-dependent dynamic offset $\boldsymbol{x_{dyn}}$ to result in the maximum vessel offset $\boldsymbol{x_{max}}$. A large portion of the FOWT offset may derive from the rotor thrust force during normal operation modes. This creates a possibility for a peak $\boldsymbol{x_{mean}}$ condition to occur during normal power production modes. This aspect sets FOWTs apart from conventional offshore systems

restoring force of the entire intact (or damaged) mooring system should be assessed when calculating x_{mean} offsets. Strength analysis should be performed on individual lines, anchors, shackles, and other mooring components using the axial tension magnitude.

The procedure discussed in Fig. 20 represents the force/displacement relationship for a line with constant properties during its deployment life—a valid assumption for chain and wire rope. Fibre rope properties will vary throughout its life span. When determining the maximum offsets and peak tension loads, it is necessary to repeat the analysis to consider variability in the rope stiffness and elongation.

Similarly, ISO 19901-7 (2013) adopts the following analogy to Eq. (7) and (8) for maximum frequency-domain tension analysis:

$$T_{extreme} = T_{static} \pm T_{wf_{max}} \tag{9}$$

The static tension T_{static} in Eq. (9) is calculated based on the tension measured at relevant offset $\left(x_{max} - x_{wf_{max}}\right)$ or $\left(x_{min} - x_{wf_{max}}\right)$, which is different from the definition of T_{mean} (ISO 19901-7 2013). In contrast, the tension analysis in API RP 2SM (2014) is given as:

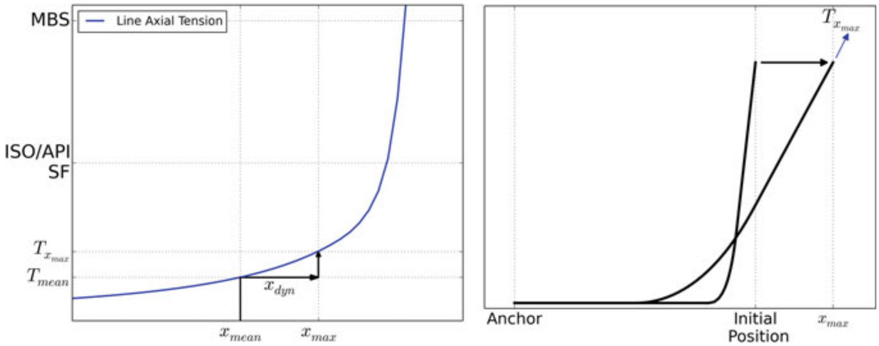


Fig. 20 Interpretation of Eq. (7)/(8) applied to a mooring system. The mean offset $\boldsymbol{x_{mean}}$ presents the offset due to steady forces from current, drift loads, and the average wind thrust. $\boldsymbol{x_{mean}}$ contributions can be significant because the rotor thrust loads are large in FOWTs. The dynamic offset, $\boldsymbol{x_{dyn}}$ are derived from cyclical loads combined from low-frequency and wave-frequency content

$$T_{max} = T_{mean} + \mathrm{MAX}\left(T_{dyn_1}, T_{dyn_2}\right) \tag{10}$$

where the mean tension T_{mean} represents the axial line force at the mean vessel displacement, i.e. at x_{mean}. The dynamic tensions $T_{dyn_1} = \left(T_{lf_{max}} + T_{wf_{sig}}\right)$ and $T_{dyn_2} = \left(T_{wf_{max}} + T_{lf_{sig}}\right)$ are defined as:

- $T_{lf_{max}}$—maximum low-frequency tension
- $T_{lf_{sig}}$—significant low-frequency tension
- $T_{wf_{max}}$—maximum wave-frequency tension
- $T_{wf_{sig}}$—significant wave-frequency tension

Note that $T_{x_{max}}$, $T_{extreme}$ in Eq. (9), and T_{max} in Eq. (10) are not necessarily identical. Equation (9) and/or Eq. (10) can be utilised as alternative design criteria, but it is often used in parallel with Eqs. (7) and (8). Although the demonstrated procedure is performed using a quasi-static method, the analysis should be followed up with a dynamic simulation studies. The rigors offered by dynamic, fully-coupled simulations entrust that non-linearities are captured and resonance matching between the platform, tethers, and environment is not overlooked.

3.4 *Design Challenges*

Although there are many facets to investigate when designing permanent moorings, the nucleus of the design is initiated with the anchor selection based on soil holding capacity. Strength analysis follows next to ensure mooring components and line tensions remain below acceptable safety factors. If design fails to meet the acceptance criteria, designers have the option to increase the material diameter or other viable alternatives to augment strength. As the mooring design matures, follow-up studies could be required in other areas, including but not limited to:

- Fatigue life and limit states
- VIV (vortex-induced-vibration) damage
- Damage conditions
- Anchor holding strength
- Installation tolerances
- Component strength
- Touchdown point
- If applicable, creep rupture and abrasion

Installation tolerance and sensitivity to anchor positioning errors should be assessed (Majhi and D'Souza 2013). Incorrect anchor placement or deviations in the line length from the assessed conditions could trigger failures, which can be exacerbated by the shallow waters FOWTs are deployed in. The shallow water poses a design challenge due to the large horizontal FOWT offset as a ratio of water depth.

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